Economic Regulation Authority

Energy price limits 2022

Draft determination

December 2022

D254581

Economic Regulation Authority

Level 4, Albert Facey House

469 Wellington Street, Perth WA 6000

Telephone 08 6557 7900

Email info@erawa.com.au

Website www.erawa.com.au

This document can also be made available in alternative formats on request.

National Relay Service TTY: 13 36 77

Invitation to make submissions

Submissions are due by 4:00 pm WST, Tuesday 3 January, 2023.

The ERA invites comment on this paper and encourages all interested parties to provide comment on the matters discussed in this paper and any other issues or concerns not already raised in this paper.

We would prefer to receive your comments via our online submission form https://www.erawa.com.au/consultation

You can also send comments through:

Email: publicsubmissions@erawa.com.au
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Please note that submissions provided electronically do not need to be provided separately in hard copy.

All submissions will be made available on our website unless arrangements are made in advance between the author and the ERA. This is because it is preferable that all submissions be publicly available to facilitate an informed and transparent consultative process. Parties wishing to submit confidential information are requested to contact us at info@erawa.com.au.

For further information please contact

General Enquiries

Adrian Theseira
Ph: 08 6557 7901
info@erawa.com.au

Media Enquiries

Danielle Asarpota
Ph: 0428 859 826
media@erawa.com.au

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Executive summary

In the Wholesale Electricity Market (WEM), participants submit price and quantity offers to supply electricity for each 30-minute trading interval. Offers into the energy markets (short term energy market and balancing market) are subject to a set of energy price limits to mitigate the exercise of market power. These energy price limits are set based on the short run marginal cost of the highest cost generating works in the South West Interconnected System (SWIS).

The WEM Rules specify two maximum energy price limits:[1]

- The maximum Short-Term Energy Market (STEM) price is the price limit that is applicable to all offers except those from liquid-fuelled (diesel) generation. The ERA annually reviews this price limit.
- The alternative maximum STEM price applies to offers from generators that use diesel for generating electricity. This price limit is indexed to the diesel price. The Australian Energy Market Operator (AEMO) resets this price limit monthly based on prevailing distillate prices. The ERA annually reviews the formula for indexing this price limit.

This draft determination explains how the ERA has determined the proposed revised values for the maximum STEM price and the indexation formula for the alternative maximum STEM price.

The ERA is seeking feedback from stakeholders on the proposed energy price limits and in particular, the assumptions underlying the parameters used to determine the energy price limits. After considering feedback from stakeholders, the ERA will publish a final determination. The final revised energy price limits will take effect on a date specified by AEMO.

The WEM Rules require that the price limits be set based on the supply cost of an existing 40 megawatt (MW) open cycle gas turbine in the SWIS that is expected to have the highest cost of energy supply. Consistent with previous reviews, the ERA considered Synergy's Pinjar units and Goldfields Power's Parkeston units as generators that could satisfy this criterion.

The WEM Rules include a method for determining the price limits, which encompasses an estimate of fuel costs, heat rate at minimum capacity and variable operating and maintenance costs. The method also includes a risk margin to account for uncertainty in determining the supply cost of the highest cost generator.

The energy price limits should reflect the upper boundary of the supply cost for the highest cost generator so that, under a set of extreme operating conditions, the generator is able to recover its generation costs. As these extreme conditions do not apply all the time, the supply cost calculated for the energy price limits will tend to be greater than the highest cost generator's supply cost under "normal" conditions and greater than the price at which the highest cost generator might be expected to offer energy into the STEM or balancing market under normal conditions.

[1] There is also a minimum energy price limit – the minimum STEM price – which is the lowest price that can be offered in the balancing market. The ERA has a separate obligation to review the minimum STEM price and therefore it is excluded from this determination. For clarity, any reference to the 'energy price limits' in this paper refers only to the maximum price limits (maximum STEM price and alternative maximum STEM price). For more information on the minimum STEM price, see: ERA, 2022, *Minimum STEM Price Review*, (online).

Revised price limits[2]

The ERA's analysis concluded that the Parkeston units continue to be the highest cost 40 MW open cycle gas turbine in the SWIS, and therefore sets the price limits. The ERA proposes the maximum STEM price of $306/MWh. This is higher than the current maximum STEM price of $290/MWh, which took effect on 1 February 2022.

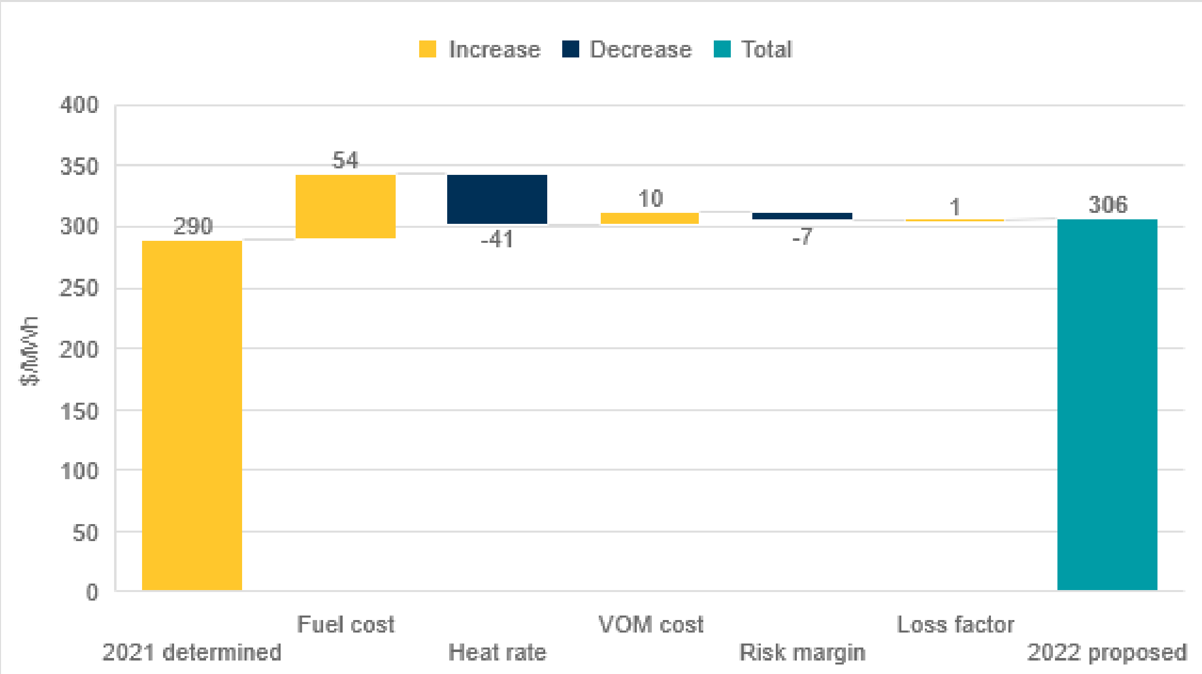
The ERA also proposes the following indexation formula to determine the alternative maximum STEM price:

$$alternative\ maximum\ STEM\ price = 37.263 + 26.051 \times\ diesel\ price\ (\$/GJ)$$

At the current distillate price of $34.1/GJ (net of excise and goods and services tax), the ERA's draft revised indexation formula yields a higher value for the alternative maximum STEM price of $926/MWh when compared to $898/MWh using the indexation formula that took effect on 1 February 2022.

The change in the estimated price limits is largely due to changes in the average fuel cost, the length of short dispatch cycles used to determine variable operational and maintenance (VOM) costs, and the Parkeston units' efficiency in converting fuel to electricity (heat rate), as illustrated in Figure 1 and further explained below.

Figure 1: Change in components of the energy price limits calculation from the ERA's previous determination



Note: Totals may not add due to rounding.

Firstly, the average fuel cost component of the calculation has increased to $12.3/GJ, compared to $10.1/GJ in the ERA's previous determination. This is driven by a forecast increase in delivered gas prices over the upcoming 12-month period, which has the effect of

2 The price limits have been determined using the latest information available. The ERA can revise the price limits over the coming year if it receives evidence that a facility cannot recover its costs because its costs are larger than that considered in this determination of the price limits.

increasing the maximum STEM price by $54/MWh compared to the current price limit. This analysis is presented in section 2.3 of this report.

Secondly, the ERA has refined its measure of short dispatch cycles from six hours to four hours. The energy price limits are modelled over scenarios where a generator is supplying electricity for a short period of time because the generator would generally observe higher costs per unit of electricity generated when operating over fewer intervals and smaller dispatch quantities. The ERA considers the reduction to four hours appropriate because it aligns with the duration of the observed daily peak period for electricity demand. A decrease in the observed duration of the daily peak in electricity demand resulted in a decrease in the average quantity of dispatch, which leads to an increase in the average VOM cost of the Parkeston units as the costs are spread across fewer dispatch quantities. This has the effect of increasing the maximum STEM price by $10/MWh. The ERA's reasoning is presented in section 2.2 of this report.

Thirdly, the ERA has relied on updated information regarding the facility's efficiency when generating electricity using different fuel sources. As part of its determination, the ERA received two heat rate curves from Goldfields Power illustrating the Parkeston units' operation using gas and diesel respectively. The Parkeston units are more efficient at generating electricity using gas instead of diesel, resulting in a lower operating cost when using gas. The ERA has used the best available source of information and relied on the updated gas-fuelled generation heat rate curve to determine the maximum STEM price, as this price limit applies to gas-fuelled generators. This has the effect of decreasing the maximum STEM price by $41/MWh; however, the decrease is offset by the effect of the two changes outlined above. This is presented in section 2.4 of this report.

1. Introduction

In the WEM, participants offer energy and ancillary services to meet real-time demand for energy. Offers into the energy markets (STEM and balancing market) are based on the cost of supply and are subject to a set of price limits to mitigate the exercise of market power.[3] These price limits are set based on the short run marginal cost of the highest cost generating works in the SWIS.[4]

The energy price limits comprise:

- The maximum STEM price: this applies to offers from all facilities except those using diesel as the fuel source.
- The alternative maximum STEM price: this applies to generators that use diesel as a fuel source, which typically have a higher cost of supply than generators that use fuel sources other than diesel.
- The minimum STEM price: this is currently set at negative $1,000/MWh and is not part of this review.[5]

For clarity, any reference to the energy price limits or price limits in this document refers only to the maximum STEM price and the alternative maximum STEM price, as the minimum STEM price is excluded from this review.

The price limits were previously determined by the ERA in 2021 and took effect from 1 February 2022. The maximum STEM price is currently set at $290/MWh. The alternative maximum STEM price is indexed to the diesel price and is updated by AEMO every month for the following month. Based on the diesel price as of November 2022, the alternative maximum STEM price is $1,018/MWh.[6]

Since 2017, the maximum STEM price has varied between $235/MWh and $351/MWh, resulting from changes in input costs and calculation methods. However, over the same period, the STEM and balancing market have seldom settled at the price cap until recently. As shown in Figure 2, there is a significant increase in the number of intervals where the balancing market cleared at the maximum STEM price in 2022 compared to previous years. The ERA notes that approximately half of these events occurred over September and October 2022, largely due to a decrease in the availability of coal-fired generation.[7]

Historical price limits and market clearing prices are presented in Appendix 4.

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3 Other market power mitigation mechanisms in the WEM include mandatory provision of capacity in the energy markets and ex post market monitoring. These mechanisms are currently being reviewed by EPWA as part of its broader market power mitigation strategy. See: EPWA, 2022, *Market Power Mitigation Strategy – Consultation Paper*, (online).

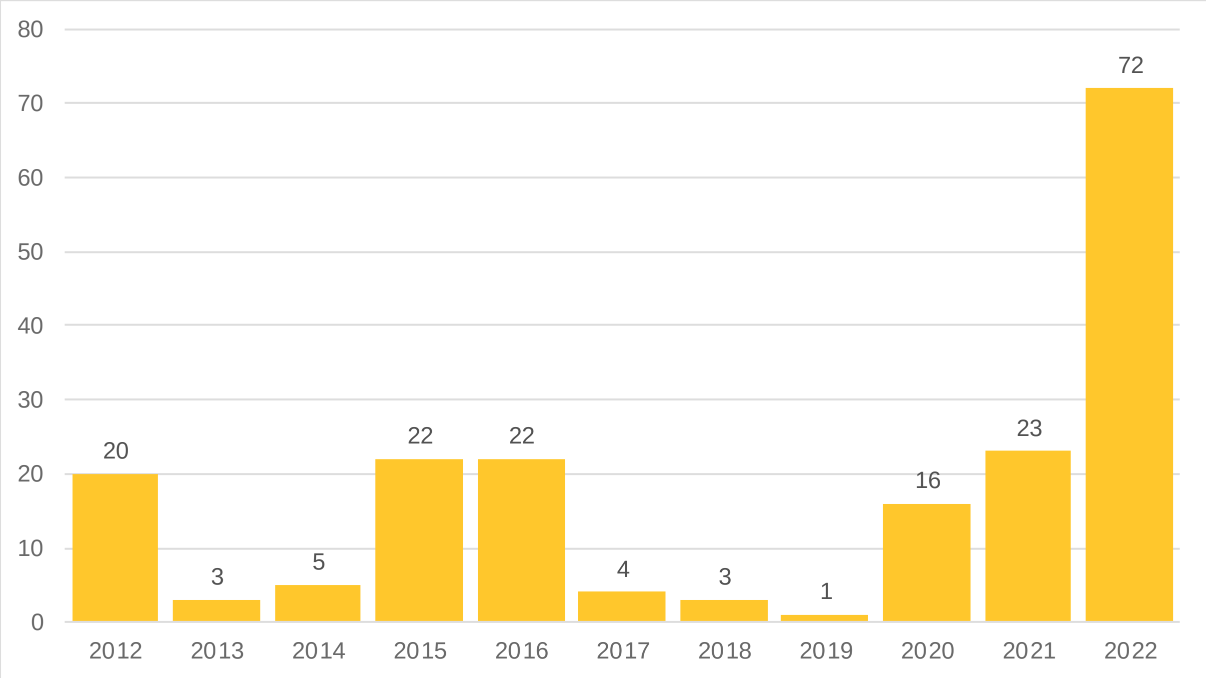
4 Short run marginal cost is the additional cost of producing one more unit of output from an existing generation plant. In the context of this paper, SRMC refers to the increase in the total production cost arising from the production of one extra unit of electricity and is measured in dollars per megawatt-hour ($/MWh).

5 The ERA has a separate obligation under clause 6.20.13 of the WEM Rules to annually review the minimum STEM price. The ERA completed its 2022 review and concluded that the current minimum STEM price of negative $1,000/MWh is appropriate. ERA, 2022, *Minimum STEM price review 2022 – Final determination*, (online).

6 AEMO, 2022, Current prices and limits, (online).

7 Synergy's 318 MW Collie Power Station is on a forced outage for three months until 1 January 2023 due to coal supply constraints. AEMO, 2022, WEM, Market Data, [accessed 11 November 2022], (online).

Figure 2: Number of times the balancing market cleared at the maximum STEM price



Source: ERA's analysis using public data published by AEMO.

Note: 2022 data is until 1 November 2022. 2012 data is from the commencement of the balancing market (1 July 2012).

The ERA recognises the purpose, principles and method for determining the energy price limits has recently been reviewed by Energy Policy WA (EPWA).[8] EPWA has finalised its design of the future energy price limits framework and proposed a range of changes, including:

- A single cost-based 'energy offer price ceiling', set at the highest reasonable operating cost plus a margin. This would replace the existing mechanism of two maximum price limits.
- The WEM Rules will no longer specify a certain fuel source or type of generator for the ERA to consider in determining the price limit. The ERA will have discretion to consider the appropriate technology upon which to base the price limit.
- The ERA will determine the price limits triennially using principles and processes outlined in the WEM Rules. The ERA will have discretion to nominate indexation methods and schedule for price escalation between triennial determinations, such as inflation or fuel prices.
- In exceptional circumstances, the ERA may bring the next triennial review forward.

1.1 The ERA's obligations under the WEM Rules

The ERA is responsible for annually reviewing the appropriateness of the energy price limits.[9]

The ERA may propose revised values for the energy price limits based on its estimate of the short-run marginal cost of the highest cost 40 MW open cycle gas turbine (OCGT) in the

8 EPWA, 2022, *Market Power Mitigation Strategy – Information Paper*, pp. 14-17, (online).

9 Wholesale Electricity Market Rules, 1 September 2022, clause 6.20.6, (online).

SWIS.[10] The ERA must use the following formula and determine appropriate values for each of the parameters of the formula:

$$(1 + Risk\ Margin) \times \frac{Variable\ O\&M\ Cost\ +\ (Heat\ Rate\ \times\ Fuel\ Cost)}{Loss\ Factor}$$

where:

a. $Risk\ Margin$ 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.

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

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

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

e. $Loss\ Factor$ is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the Reference Node.[11]

The ERA must publish a draft report for consultation, describing how it determined any revised values of the maximum energy price limits.[12] After considering the submissions, the ERA must propose final revised values for the maximum energy price limits.[13] The revised values proposed by the ERA will take effect on a date specified by AEMO.[14]

1.1.1 Information for the ERA's determination

The determination of the energy price limits requires data to estimate generators' fuel costs, heat rate and VOM costs. The ERA requested and received data from asset owners on their respective generating units, which included:

- Historical data, such as dispatch profiles, heat rates, and fuel and non-fuel costs.
- Estimates of the generators' VOM costs.
- Forecasts or assumptions underlying future fuel and non-fuel costs over the upcoming 12-month period.
- Assumptions about expected generation activity in the WEM over the upcoming 12-month period and beyond.

The ERA has evaluated the information received from all sources to determine which source would be the best input into the energy price limits calculation. Where the information has differed significantly from the information relied on in previous reviews, the ERA has placed a greater weight on the information provided directly by the asset operator. The ERA has

[10] Ibid, clause 6.20.7(a).

[11] Ibid, clause 6.20.7(b).

[12] Ibid, clause 6.20.9.

[13] Ibid, clause 6.20.10.

[14] Ibid, clause 6.20.11.

adopted this approach on the basis that the asset operator would be best placed to provide information on its generator's operating patterns and cost profile.

Some of the information required for the ERA's analysis is either confidential or commercial-in-confidence. As a result, the underlying confidential information has been redacted in this document, but the ERA's analysis ensuing from the provided information is published.

2. The ERA's process of determining energy price limits

The WEM Rules require the ERA to determine the price limits based on the supply cost of the highest cost 40 MW open cycle gas turbine generator in the SWIS. The method outlined in the WEM Rules makes explicit allowance for the fact that there is uncertainty in estimating such costs. There is no single supply cost for all operating conditions, so the price limits are set after considering a range of possible values.

Price limits are reviewed annually and are set to strike the balance between being:

- Low enough to limit the ability of generators with market power to charge prices above their reasonable expectation of the short run marginal cost of the electricity supplied.[15] This protects market customers from high prices that could result from generators exercising market power in the energy markets.
- High enough so that the high-cost generators in the SWIS can recover their costs of electricity supply in the presence of highly variable market conditions. Supply costs can change due to changes in input costs and operating conditions. The maximum STEM price is to be high enough so that short-term gas price variations do not force facilities with dual fuel capability to regularly switch from using gas to using liquid fuel to recover their supply costs.

The ERA has based its determination on an operational scenario of the highest cost generator supplying energy for a short period of time at its minimum stable generation level and when its cost of fuel consumption is high. The energy price limits should reflect the upper boundary of the supply cost for the highest cost generator so that, under a set of extreme operating conditions, the generator is able to recover its generation costs. As these extreme conditions do not apply all the time, the supply cost calculated for energy price limits will tend to be greater than the highest cost generator's supply cost under "normal" conditions and greater than the price at which the highest cost generator might be expected to offer energy into the STEM or balancing market under normal conditions. The reason for adopting this conservative approach in determining the energy price limits is explained further below.

There is uncertainty in estimating the inputs to the calculation of the price limits. The price limits – or the indexation formula for the alternative maximum STEM price – are set based on a forecast of input costs and operating conditions generally over the coming year, which is referred to as the planning year in this report. The determination of the price limits uses a possible range of variable input values over the planning year based on the best information available at the time, such as a range of possible values for a generator's mean heat rate at minimum capacity. This calculation method provides a range of possible values for the supply cost of the highest cost generator in the SWIS over the coming year. From this, the ERA generates a probability distribution for the generator's supply cost.

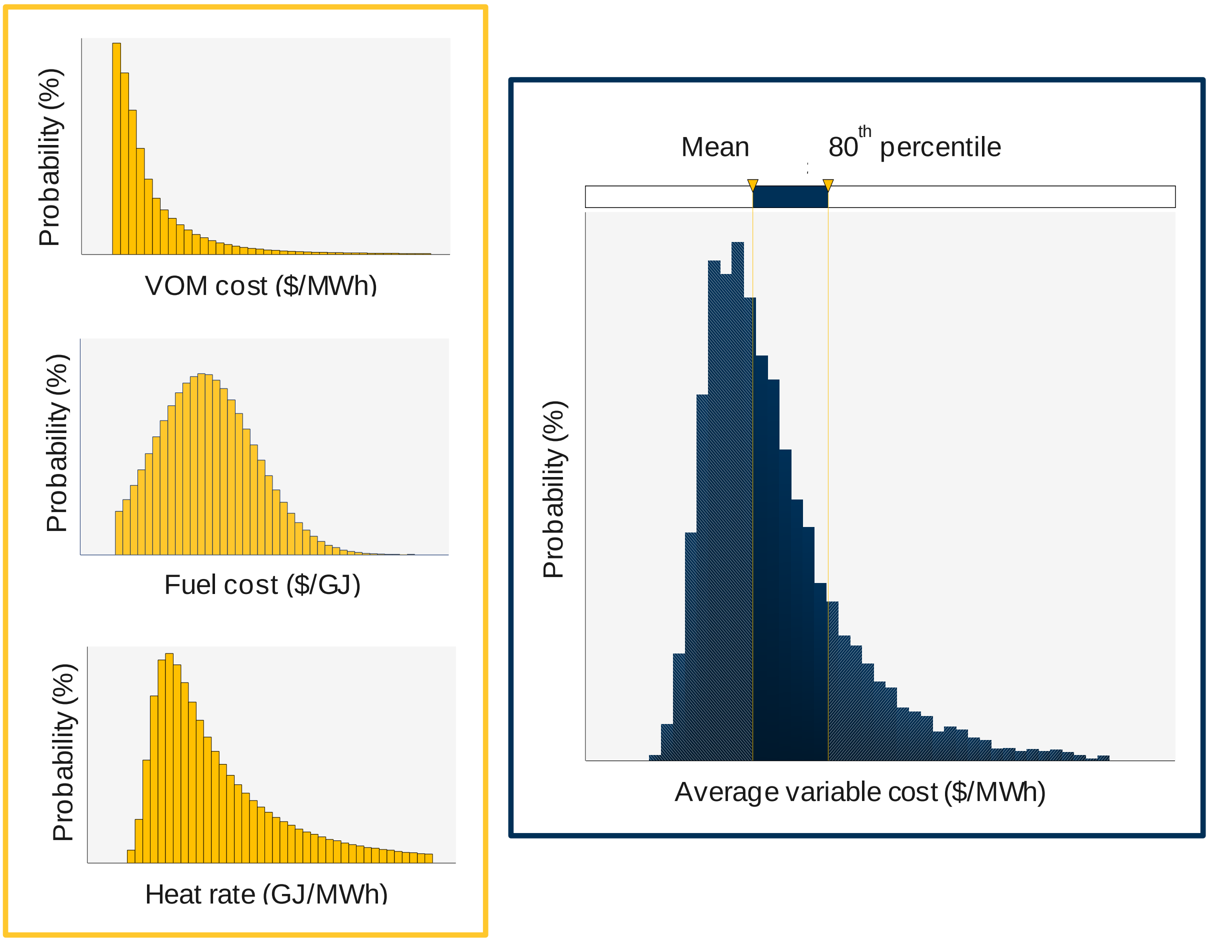
The price limits are set at a level higher than the average value of the probability distribution – generally the 80th percentile in previous reviews – to account for the uncertainty in the underlying input cost calculations. The WEM Rules recognise this through the inclusion of a

[15] The WEM Rules require the ERA to review the method for setting the energy price limits every five years. The ERA considers the intention of the price limits is to mitigate the exercise of market power by participants, as the WEM Rules require the ERA to consider "the level of market power being exercised and the potential for the exercise of market power" and "the effectiveness of the methodology in curbing the use of market power" as part of its review of the method to determine energy price limits. Wholesale Electricity Market Rules, 1 September 2022, clause 6.26.3, (online).

risk margin. The risk margin is the difference between the mean and 80th percentile of the supply cost probability distribution, with the 80th percentile the effective value of the price cap.

This process is demonstrated in Figure 3.

Figure 3: Relationship between model inputs (left) and output (right)



When information is limited, or the ERA cannot infer a reasonable range for an input variable, the ERA will consider using the input value, among the range of possible values, that would provide a higher price cap. The ERA may also consider assigning higher weights to the highly uncertain input values that yield higher price limits. Taking this approach is important for two reasons.

Firstly, setting the price limits based on the higher of possible values allows generators to recover their costs. While setting the price limits too high can reduce the effectiveness of the price limits in limiting the exercise of market power, the WEM Rules contain other market power mitigation mechanisms to reduce this risk.[16] Setting the price limits too low risks under-recovery of costs for generators, which can deter the entry of generators to the SWIS or force the exit of incumbent generators. This can weaken competition in the market and raise the

[16] Under the WEM Rules, generators cannot offer bids in the STEM or balancing market beyond their reasonable expectation of supply costs. The ERA monitors generators' offers to the market and can request information from generators to assess if the offers were reasonable given the information available to generators and their input costs at the time of offering to the markets. Energy Policy WA is currently redesigning the market power mitigation strategy and proposed a range of mechanisms to mitigate the exercise of market power. See EPWA, 2022, *Market Power Mitigation Strategy – Information Paper*, (online).

long-term supply cost of electricity to consumers. This outcome would be inconsistent with the objectives of the WEM Rules.

Secondly, adopting a conservative approach by using the input value that would provide a higher price cap mitigates the risk that the risk margin may not sufficiently account for the uncertainty in the input variables. The formula in the WEM Rules for determining the price limits includes the risk margin as an input; however, in practice the risk margin has been estimated as an output of the calculations based on the range of input variables.[17]

Unless otherwise stated, the ERA has adopted a modelling approach and process that is consistent with its previous determination. The ERA has only updated the modelling where it has received new information regarding the generator's operating costs or improved the model using improved modelling assumptions where necessary.

2.1 Selecting the highest cost generating works

The WEM Rules require the energy price limits determination to be based on the short run marginal cost of the highest cost 40 MW open cycle gas turbine in the SWIS. Previous reviews have identified the industrial gas turbines at Pinjar Power Station (Pinjar units GT1, GT2, GT3, GT4, GT5 and GT7) and the aeroderivative gas turbines at Parkeston Power Station as facilities that fulfil the criteria of the WEM Rules.[18] The Parkeston units set the energy price limits in the ERA's previous determination.

The Pinjar units are owned by Synergy and the Parkeston units are owned by Goldfields Power. Both Pinjar and Parkeston gas turbine units are manufactured by General Electric (GE) to provide peaking power in the SWIS.[19]

Since the ERA's previous determination, no new 40 MW generators have been commissioned in the SWIS. As a result, the ERA has considered the 40 MW Pinjar turbines and the Parkeston turbines as the two machines for this review.

The ERA's analysis in this determination concludes that the Parkeston units continue to be the highest cost generators in the SWIS and will set the energy price limits.

The rest of this paper outlines the ERA's analysis of the Parkeston units' costs. The ERA's analysis of the Pinjar units' costs is presented in Appendix 3.

2.2 Variable operating and maintenance cost

The VOM cost component of the energy price limits calculation includes any costs incurred in operating a generator (other than fuel cost) and conducting periodic maintenance work

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17 The formula in the WEM Rules requires the ERA to estimate a generator's VOM cost, fuel cost and heat rate at minimum capacity. Given there are uncertainties associated with these variables and a range of possible values are likely, the ERA assigns a distribution to each of these input variables. The entire distribution of the input variables, not just the average of the distribution, is used to run Monte Carlo simulations and generate a probability distribution of the output, which is the generator's average variable cost. The price limit is chosen as the 80th percentile of the output distribution. This is reasonable and consistent with past practice.

18 Unless otherwise stated, any reference to the Pinjar units in this report refers to the Pinjar units 1 to 5 and 7. The larger Pinjar units (units 9-11) have a nameplate capacity of approximately 120 MW and are therefore excluded from this analysis.

19 In GE nomenclature, the Pinjar units are Frame 6B heavy duty gas turbines and the Parkeston units are LM6000PA aeroderivative gas turbines.

required to maintain the generating unit in an efficient and reliable condition. These costs mainly comprise maintenance service, parts and labour expenses. VOM costs include those maintenance expenditures that depend only on the use of the machine. For clarity, VOM costs do not cover the cost of any maintenance that is run regardless of whether the unit operates or not. The WEM Rules do not specify a method for determining VOM costs, but note it includes start-up costs and should be expressed as costs on a $/MWh basis.

An estimate of a generator's average VOM costs on a $/MWh basis requires:

- An estimate of the generator's VOM costs. These costs can be estimated using a combination of VOM costs per operating hour ($/hour), VOM costs per start ($/start) or VOM costs per unit of output ($/MWh).
- An appropriate method to spread those costs over each start or operating hour of the units, and then subsequently over each unit of energy (MWh) generated.

To estimate VOM costs, the ERA considered information from various sources, including the asset owner (Goldfields Power), the original equipment manufacturer (GE) and previous reviews of the price limits. For this determination, the ERA has estimated the Parkeston units' average VOM cost as $40.1/MWh, which is based on information provided by Goldfields Power and generally comparable to the original equipment manufacturer's estimates for similar gas turbines and Goldfields Power's previous estimates.[20]

The estimated average VOM cost of $40.1/MWh in this determination is higher than the estimated average cost of $30.1/MWh in the ERA's previous determination. This is due to two factors:

- There is an increase in the estimated VOM costs provided by Goldfields Power. These costs are consistent with costs provided in the ERA's previous determination that have been escalated for inflation. This is discussed in section 2.2.1.
- There is a decrease in the average dispatch generation observed over short dispatch cycles. The decrease can be attributed to a change in model assumptions regarding the length of short dispatch cycles. This is discussed in section 2.2.2.

An increase in costs spread across a smaller average dispatch quantity has led to an increase in the average VOM cost compared to the previous determination.

2.2.1 Estimate of VOM costs

The ERA received Goldfields Power's estimate of its VOM costs for the Parkeston units. Goldfields Power has a range of contracts for the operation and maintenance of the Parkeston units.

Goldfields Power provided its short run marginal cost estimates which included:

- Start-up costs, which include start-up fuel consumption.
- Costs per operating hour, which cover long-term major variable maintenance and overhaul costs.
- Other VOM costs.

[20] In 2021, the ERA received advice from GE on the approximate cost and timeframe for a major overhaul for a LM60000PA turbine, which was comparable to the cost per operating hour provided by Goldfields Power.

These costs are higher than the costs Goldfields Power provided for the ERA's previous determination. The ERA considers the escalation in Goldfields Power's costs to be reasonable.

The VOM cost component of the price limits calculation must be expressed as a cost per unit of energy generated ($/MWh). The first two cost items above are converted to a cost per MWh of electricity generated based on the possible duration of short dispatch cycles.[21] The choice of short dispatch cycles for this conversion ensures the estimated cost per start is spread over a short period of time, and hence, the estimated cost per unit of energy generated reflects the very high-cost operating conditions of the units. This conversion approach is further explained in section 2.2.2.

2.2.2 Deriving VOM costs as a cost per unit of energy generated

Determining the VOM cost input of the price limits calculation requires all VOM cost inputs to be provided on a $/MWh basis. An estimate of the energy generated each time the machine is started is required to convert estimates of VOM costs, expressed in dollars per start or dollar per operating hour to costs/MWh. This cost conversion is dependent on the duration of operation and load when the machine is dispatched, which can vary significantly for each dispatch of the machine.

A dispatch cycle is used to capture such variations in the form of a dispatch cycle duration and output distributions. This is explained in detail in Appendix 2.

The analysis uses historical dispatch data to characterise the dispatch cycle distribution of Parkeston units through the following sampled variables:

1. Dispatch duration over a "short" dispatch cycle, expressed in hours. The ERA considered shorter dispatch cycles of up to four hours in this determination compared to previous determinations. This is discussed further below.

2. Capacity factor as a function of dispatch duration over short dispatch cycles, expressed as a percentage.[22] The ERA developed a distribution of capacity factors as observed over short dispatch cycles, with an average capacity factor of 42.6 per cent. This is discussed further in Appendix 2.

3. Maximum capacity, expressed in megawatts (MW). The ERA assumed a constant maximum capacity, based on Goldfields Power's experience in operating the Parkeston units and the OEM recommendation of maximum output. This is discussed further in Appendix 2.

The product of these three variables yields the amount (MWh) of electricity generated per start of the machine. The whole distribution, not just the average of the distribution, of each of the three variables is used to derive a distribution of electricity generated per start of the machine. The average of the distribution of dispatch generation over short dispatch cycles is used to derive VOM costs on a $/MWh basis.

21 A dispatch cycle is the process of starting a generator, synchronising it to the electricity system, loading it up to minimum load as quickly as possible, and operating the unit between the minimum and maximum loading and running it down to zero output level for shutdown.

22 Capacity factor over a dispatch cycle (expressed in percentage) is the amount of energy generated over the dispatch cycle (expressed in MWh) divided by the product of maximum capacity (MW) and dispatch cycle duration (hours). A capacity factor of 100 per cent would indicate the generator was operating at its full capacity over the duration of the dispatch cycle.

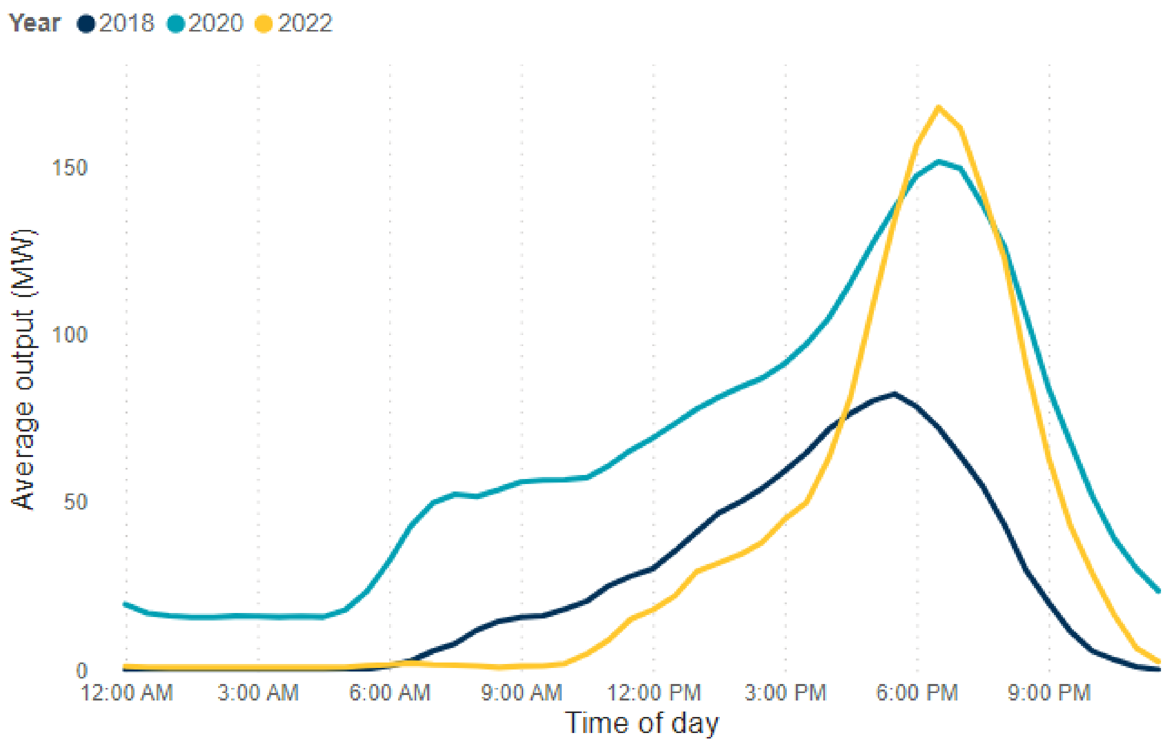
Refined model assumption of "short" dispatch cycles

Consistent with previous reviews, the analysis considers short dispatch cycles, instead of all dispatch cycles, to derive VOM costs on a $/MWh basis. This ensures the estimated VOM cost is spread over relatively short dispatch run times and the estimated cost reflects high-cost operating conditions for the machines, consistent with the ERA's principles outlined in section 2 to determine the energy price limits.

In this determination, the ERA has refined its model assumption of a "short" dispatch cycle to a maximum of four hours. In previous reviews, the length of short dispatch cycles was restricted to six hours. The ERA's decision to use a four-hour maximum has been informed by analysis undertaken by Energy Policy WA (EPWA), which indicated that the duration of the daily peak periods in electricity demand is four hours.[23]

As seen in Figure 4, the daily peak in electricity generated over the summer period has increased in quantity and decreased in duration over time. In these circumstances, the ERA considers that it is appropriate to use four hours as the maximum duration for a short dispatch cycle.

Figure 4: Average generation per time of day



Note: this series shows the average daily output of peaking generators over the summer months of December, January and February (i.e. the 2022 series shows December 2021 to February 2022).

The energy price limits are modelled over scenarios where a generator is supplying electricity for a short period of time – such as the evening demand peak – because a generator would generally observe higher costs per unit of electricity generated when operating over fewer intervals and smaller dispatch quantities. A decrease in the observed duration of the daily

[23] EPWA, 2022, *Market Power Mitigation Strategy – Consultation Paper*, p. 34, (online).

peak in electricity demand results in an increase in the average VOM cost of the Parkeston units, as the costs are spread across fewer dispatch intervals.

The ERA analysed the Parkeston units' operation over dispatch cycles between 0.5 and 4.0 hours, over the past three years. The analysis indicated the Parkeston units' average dispatch duration and generation over short dispatch cycles – up to 4 hours – is 2.6 hours and 45.1 MWh respectively.[24]

Average VOM cost distribution

The conversion of the VOM cost items for the Parkeston units is set out below and summarised in Table 1:

- The cost per start ($/start) is divided by the product of sampled run time (hours), capacity factor (%), and maximum capacity (MW) to be expressed on a cost per MWh basis.
- The cost per operating hour ($/hour) is divided by the product of the capacity factor (%) and the maximum capacity (MW) and expressed on a cost per MWh basis.
- The cost per unit of energy generated ($/MWh) is already provided in a cost per MWh basis and is added to the other costs.

The resulting average VOM cost is $40.1/MWh.

Table 1: Estimate of VOM costs for Parkeston units[25]

Item	Unit	Value	Notes
Cost per operating hour	$/hour	[redacted]	Contracted fee to cover long-term major maintenance and overhaul costs.
Cost per start	$/start	[redacted]	Includes start-up fuel consumption.
Cost per unit of energy generated	$/MWh	[redacted]	Other VOM costs.
Average duration of dispatch per start (short dispatch cycles)	Hours	2.6	Average of the distribution of dispatch duration over short dispatch cycles. See details in Appendix 2.
Average energy generated per start (short dispatch cycles)	MWh	45.1	Average of the distribution of energy generated over short dispatch cycles. See details in Appendix 2.
Average capacity factor as a function of run time (short dispatch cycles)	%	42.6	Average of the distribution of capacity factors over short dispatch cycles. See details in Appendix 2.
Mean VOM cost	**$/MWh**	**40.1**	**Average of the distribution of VOM costs.**

Source: The ERA's analysis of the Parkeston units' data as provided by Goldfields Power.

24 In comparison, the ERA's analysis in the previous determination indicated the Parkeston units' average dispatch duration and generation over short dispatch cycles – up to 6 hours – is 3.2 hours and 67.4 MWh, respectively.

25 The values redacted in this table are based on confidential information provided to the ERA.

2.3 Fuel cost

The WEM Rules require the maximum STEM price to be determined using gas as the fuel source and the alternative maximum STEM price using distillate. In recent years, the cost of fuel – the product of heat rate and fuel price – has accounted for 40 per cent to 50 per cent of the maximum STEM price, and 60 per cent to 70 per cent of the alternative maximum STEM price. Price limits are highly sensitive to fuel prices. A $1/GJ increase in the fuel price increases the price limits by approximately $25/MWh.

The trade of natural gas in Western Australia is largely through bilateral contracts between suppliers and consumers of gas. Recent reviews of the price limits used gas price forecasts based on information available on the maximum monthly gas price cleared on the gasTrading platform – a trading platform through which sellers and buyers generally trade gas on a month-ahead basis.[26]

To estimate the fuel cost component of the energy price limits calculation, the ERA considered Goldfields Power's expected cost of sourcing gas over the next 12 months, public sources of data and the ERA's forecast of maximum monthly gas prices on the gasTrading platform (Appendix 1).

In estimating fuel supply costs included in the energy price limits calculation, the ERA has considered that the fuel supply costs are intended to reflect the fuel consumption cost under extremely high-cost operating conditions, such as for short periods of operation at or around the minimum stable level of generation, consistent with the principles outlined in section 2.

To estimate the fuel supply cost of the Parkeston units, the ERA relied on its forecast gas price of $6.70/GJ (undelivered) over the next 12 months and a gas transportation cost of $4.98/GJ, based on tariffs applicable for the uncovered capacity on the Goldfields Gas Pipeline (GGP). The tariff for the uncovered capacity on the pipeline is substantially higher than the tariff applicable for the covered capacity of the pipeline.[27,28] Overall, this yields an average delivered gas price of $12.3/GJ, after the application of a daily load factor as explained in section 2.3.1.1.

After considering all available sources of information, the ERA has assessed its forecast gas price as the preferred indicator of the cost of acquiring gas in the market over the forward period. The ERA's analysis also includes a distribution of gas costs, which allows for a consideration of possible variations in the cost of acquiring gas for Goldfields Power when modelling energy price limits. This is explained in more detail in section 2.3.1.

The transportation service capacity on the covered capacity on the GGP is expected to be fully contracted over the coming year. When transport service capacity is fully contracted, the opportunity cost varies depending on on-selling negotiations between parties with existing access to gas and transport service. The ERA assessed available capacity and supply and demand conditions on the GGP in estimating the gas transportation cost of $4.98/GJ in its estimate of the energy price limits. This is detailed in section 2.3.2.

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[26] gasTrading Australia Pty Ltd, 2022, Spot Market [retrieved on 7 November 2022], (online).

[27] Gas transportation tariffs for reference services on the covered capacity of the pipeline are based on regulated tariffs determined by the ERA. However, some of the assets forming part of the pipeline are a non-scheme pipeline for which the regulator does not set regulated tariffs. The transportation tariff on the uncovered capacity of the pipeline is published by the pipeline operator.

[28] The ERA sets reference tariffs for the covered capacity on the GGP. Parties negotiate transportation tariffs for individual contracts. The ERA has estimated gas transmission cost to the Parkeston Power Station based on the covered and uncovered tariffs on the GGP, with an average of $1.47/GJ and $4.98/GJ, respectively. See: APA, 2022, Tariffs and terms, [accessed 11 November 2022], (online) and ERA, 2022, Goldfields Gas Pipeline, Tariff Variations, [accessed 11 November 2022], (online).

2.3.1 Forecast of gas price

The sourcing of gas in Western Australia is mainly based on bilateral trading agreements between gas suppliers and generators. Some generators purchase gas through long-term forward contracts (typically 5 years to 20 years) to limit their exposure to the risk of variable fuel prices. Others might source all or part of their gas through short-term trading platforms (between a month to a day ahead). Apart from the gasTrading platform, prices and trade quantities for other trading arrangements or bilateral contracts are not published.[29]

The ERA considered two sources of information on the price of natural gas in Western Australia to forecast the opportunity cost of using gas for electricity generation for the Parkeston units over the review period:[30]

- The ERA's forecast of natural gas prices based on observed prices in the gasTrading platform.[31] The ERA also considered the volume weighted average price of gas, as published by the Department of Mines, Industry, Regulation and Safety (DMIRS), but concluded the use of the maximum monthly spot prices from the gasTrading platform was more appropriate for forecasting the opportunity cost of using gas to generate electricity as part of this determination. See Appendix 1.
- Information from Goldfields Power on its expected fuel costs over the review period.

In preparing its forecast of gas prices, the ERA considered the general gas supply and demand conditions globally. The global energy crisis, further affected by Russia's invasion of Ukraine, has caused natural gas prices to rise to record highs. Gas market prices in eastern Australia have risen to above $25/GJ in some cities.[32] It is not clear, however, whether such rises will be seen in Western Australia where exporters of liquified natural gas (LNG) are required to make gas available to the domestic market, complementing supply from domestic-only projects.[33]

In 2022, Western Australia has experienced coal supply issues.[34] This has led to Synergy's Collie coal-fired power station being out of operation to January 2023, and the possibility that coal will have to be imported for the period following the end of March 2023.

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[29] Currently, the ERA is aware of two other short-term trading platforms in Western Australia for trading natural gas: (1) the Inlet Trading market operated by DBNGP (WA) Transmission Pty Ltd at the pipeline inlet, which enables pipeline shippers to trade imbalances, (2) the platform operated by Energy Access Services that has nine unknown foundation members. Membership of the platform is open to all buyers and sellers of gas in Western Australia.

[30] The opportunity cost of using gas for electricity generation is the value of the best alternative use of gas. For example, a generator might sell its acquired gas instead of using it for generating electricity if it earns a higher value from the sale of gas.

[31] The gasTrading platform acts as an agent for the sellers of gas and operates a spot market. Each successful bidder receives gas based on its bid price, such that the market does not clear at a single price. Each month the platform provides an indication of the quantity of gas available for sale over the next month and invites buyers to bid for the quantity of gas they require for each day over the next month. The platform then accepts the highest bid prices until all available volumes of gas are allocated. See: gasTrading Australia Pty Ltd, 2022, *Historical Prices and Volumes*, (online).

[32] Including Adelaide ($27.29/GJ), Brisbane ($25.95/GJ), Sydney ($27.06/GJ) and Wallumbilla hub ($28.03/GJ) in Queensland. Australian Energy Regulator, Gas Market Prices, (online) [accessed 9 November 2022].

[33] Government of Western Australia 2017 to 2022, Implementation of the WA Domestic Gas Policy, (online), [accessed 11 November 2022].

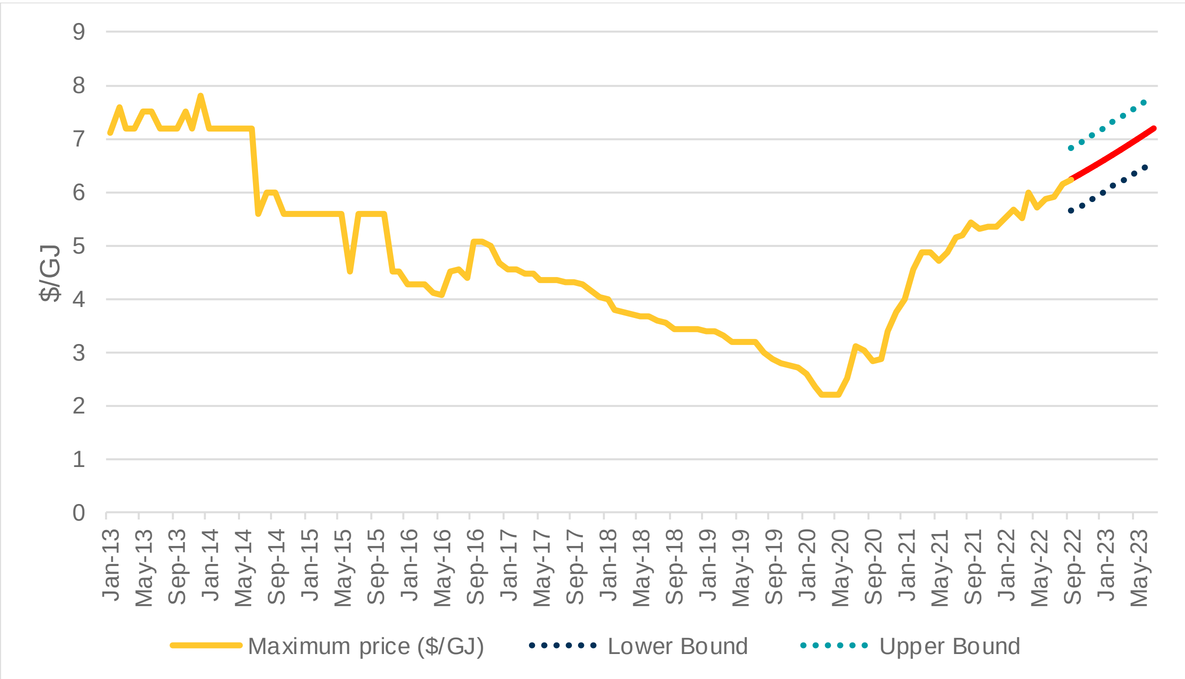
[34] Premier Coal has experienced production issues and Griffin Coal appointed receivers. The West Australian, 2022, *Coal comfort in NSW imports. Synergy ships in fuel from Hunter Valley because of big fall in production in Collie*, (online), [accessed 11 November 2022].

In its recent WA Gas Consultative Forum, AEMO noted that there was already an increase in consumption of gas for electricity generation of 11.5 percent in 2022, as compared to 2021. AEMO's base case scenario for potential gas supply and demand into the future shows a finely balanced market out to 2026.[35] It appears likely therefore, that Western Australia may experience at least some increase in gas prices in 2023.

The ERA has considered these trends in gas supply and demand and used a time series analysis to forecast gas prices over the coming year. Forecast maximum monthly gas prices based on the gasTrading Australia data ranged between $6.23/GJ for September 2022 and $7.20/GJ for July 2023, with a mean of $6.70/GJ and a standard deviation of $0.32/GJ.[36] The ERA's forecast of maximum monthly gas prices is depicted in Figure 5.

The ERA will update its analysis using more recent data ahead of its final determination.

Figure 5: Forecast (red) of maximum monthly gas prices



Source: ERA's analysis, 2022, Gas price forecast for EPL determination.

Note: Lower and upper bounds represent prediction intervals at a 95% level of confidence.

2.3.1.1 Daily gas load factor

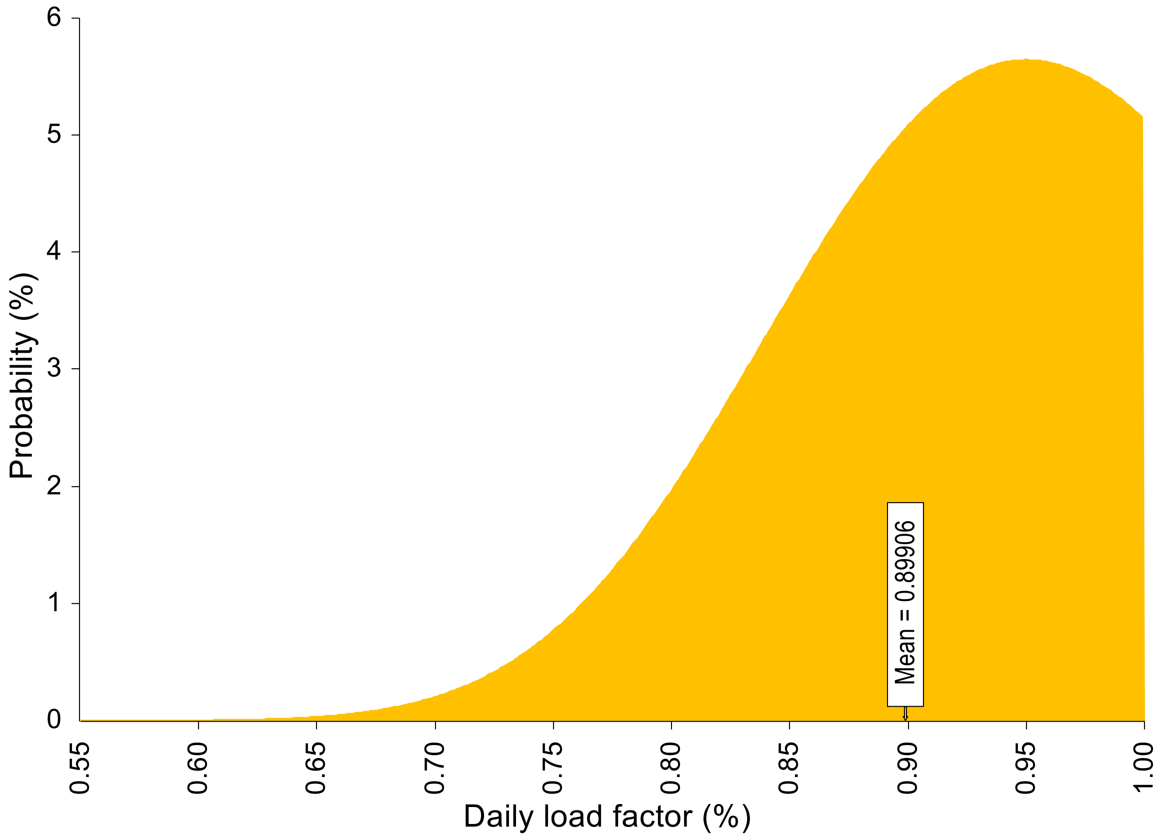
There is a risk that gas turbine generators over-estimate their consumption of gas for electricity generation when procuring gas and consequently pay for gas that they do not use. To account for this uncertainty, the modelling applies a gas load factor distribution to the gas price

[35] AEMO, 2022, WA Gas Consultative Forum, 2 November 2022, Slide 17, (online) [accessed 11 November 2022).

[36] Notably, the maximum monthly price for September 2022 on the gasTrading website is $6.25/GJ and the minimum price is $5.80/GJ. These values are very consistent with the values predicted by the model for September 2022, which were a maximum monthly price of $6.23/GJ, with a lower bound of $5.83/GJ.

distribution (Figure 6). The method divides the gas cost by the loading factor (of average 0.8991).[37] This increases the gas cost by 11 per cent on average.

Figure 6: Capped distribution for modelling uncertainty in spot gas daily load factor



2.3.2 Delivered gas price estimated for Parkeston units

Gas is delivered to the Parkeston units on the Goldfields Gas Pipeline (GGP) via the Parkeston lateral.[38] Some of the assets on the GGP are covered under the access regulatory regime of the *National Gas (Western Australia) Act 2009*.[39] Gas transportation tariffs for reference services on the covered capacity of the pipeline are based on regulated tariffs determined by the ERA.

However, some of the assets forming part of the pipeline are a non-scheme pipeline for which the ERA does not set regulated tariffs. The pipeline operator has published its own tariffs and terms for a set of standard non-reference services, which is the 'uncovered' capacity tariff.[40]

The cost of transporting gas depends on the availability of covered and uncovered capacity in the pipeline and transportation service characteristics – for example, whether the service is interruptible or firm. Customised services such as variations to the reference service and services on uncovered capacity may be available on the GGP by negotiating with the pipeline operator, subject to available capacity.

[37] The loading factor of 0.8991 is the average of the probability distribution modelled between 60 per cent and 100 per cent of the daily gas supply.

[38] The Parkeston lateral is a non-scheme pipeline but is exempt from providing pricing information.

[39] APA, 2022, *Goldfields Gas Pipeline*, (online).

[40] APA, 2022, *Website: tariffs and terms*, [accessed 11 November 2022], (online)

When the pipeline capacity is fully contracted between the pipeline operator and gas consumers, the opportunity cost of transporting gas on the pipeline depends on the availability of any excess capacity available from those parties with existing contracts, and the level of additional demand for transportation service on the pipeline.

The ERA has estimated gas transport costs to Parkeston based on reference tariffs for firm reference services on the uncovered capacity of the pipeline, which are summarised in Table 2.[41] [42]

Table 2: Estimated delivered gas price to Parkeston units, uncovered tariffs

Item	Measure	Value
Toll tariff	$/GJ	0.4290
Capacity reservation tariff	$/GJ/km	0.0033
Total tariff at 100% load	**$/GJ**	**4.98**

Source: APA, 2022, (online).

In estimating a gas transportation cost to include in the energy price limits determination, the ERA considered the available capacity and supply and demand conditions on the pipeline. The ERA determined that an average gas transportation cost of $4.98/GJ is reasonable as it allows for the bilaterally negotiated price for delivering gas to Parkeston up to full cost recovery for sellers with excess gas or transportation capacity that pay prevailing gas commodity prices and the standard service uncovered transportation charge.

In determining a delivered gas price for this draft determination, the ERA has considered:

- Goldfields Power's current and expected fuel costs, provided confidentially to the ERA.
- Any arrangements Goldfields Power has in place to procure gas, provided confidentially to the ERA.
- The reference tariffs for transporting gas using the uncovered capacity on the pipeline.
- The availability of capacity on the pipeline.
- The ERA's forecast of gas prices over the coming year.

The resulting distribution of the delivered gas price is shown in Figure 7, which also includes the application of the gas load factor distribution explained in section 2.3.1.1. The average delivered gas price is estimated as $12.3/GJ.

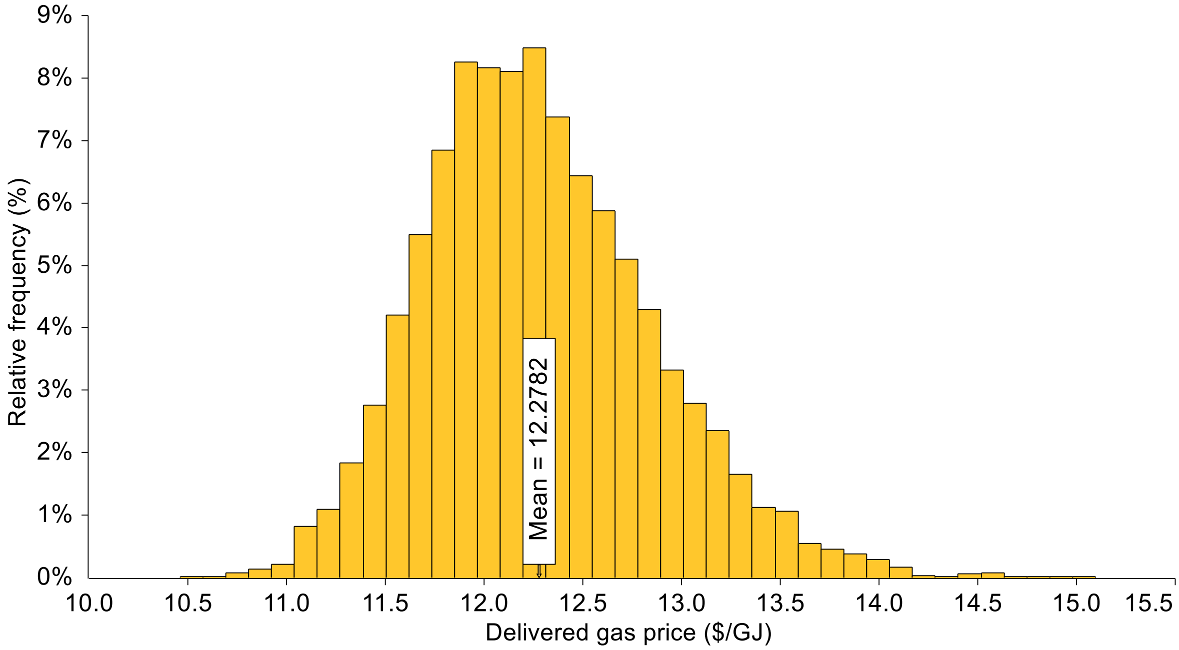
In the coming year, if evidence emerges that the delivered gas costs to the Parkeston units are larger than that considered in the determination of the maximum STEM price, and as a result Goldfields Power cannot recover its costs when using gas, the ERA can revise the price limits accordingly.

The equivalent gas price input to determine the Pinjar units' supply cost is presented in Appendix 3.

41 APA, 2022, Website: tariffs and terms, accessed 11 November 2022, (online)

42 To account for the uncertainty in cost variation, the ERA developed a distribution of gas transport costs to Parkeston by assuming the costs are normally distributed with an average of $4.98/GJ and a standard deviation of $0.15/GJ.

Figure 7: Distribution of delivered gas price, Parkeston units



Source: ERA analysis.

2.3.3 Distillate price

The WEM Rules provide for a monthly re-calculation of the alternative maximum STEM price based on prevailing fuel prices, such as the Singapore gas oil price (0.5 per cent sulphur) or another suitable published price, as determined by the ERA.[43] Since 2018, the alternative maximum STEM price has been determined using the Perth diesel terminal gate price (TGP) (net of goods and services tax and excise) as the Singapore gas oil price (0.5 per cent sulphur) is no longer widely used.[44] The Perth diesel TGP includes shipping costs and therefore considers variations in these costs due to factors such as exchange rate changes.

The ERA has based its estimate of distillate using the Perth diesel TGP, consistent with the approach taken in previous reviews. Therefore, in this analysis a reference distillate price based upon the Perth diesel TGP is assessed to define a benchmark alternative maximum STEM price component that depends on the underlying distillate price.

For the ERA's determination of the price limits, the uncertainty in the diesel price is not important because the alternative maximum STEM price is indexed to the diesel price and updated monthly. However, in modelling the gas price for the maximum STEM price, the uncertainty and level of the diesel price is relevant to the extent that it is used to cap the extreme gas prices at the level where the dispatch cycle cost would be equal for gas and for diesel firing for the nominated gas turbine technology and location. This cost parity is

[43] Wholesale Electricity Market Rules, 1 September 2022, clause 6.20.3.(b)(i), (online).

[44] Prior to 1 July 2021, AEMO was responsible for proposing revised energy price limits annually to the ERA for approval. As part of its analysis of diesel prices for the energy price limits review, AEMO's consultants relied on the Singapore gas oil price (0.5% sulphur) until 2018. In its 2018 review, AEMO's consultant instead relied on the Perth TGP on the basis that the Singapore gas oil price is no longer widely used. See: Jacobs, 2018, *Energy Price Limits for the Wholesale Electricity Market in Western Australia, Final Report*, p. 24, (online).

considered to create a cap for the distribution of gas prices used to estimate the maximum STEM price.

The average Perth diesel TGP declined significantly in early 2020, largely due to the uncertainty resulting from the COVID-19 pandemic and the decline in global oil prices caused by a significant oversupply of oil. The prices have since recovered (Figure 8), with considerable volatility in prices in 2022.

The United States Energy Information Administration (EIA) highlighted significant short- and long-term uncertainties in the liquid fuels market.[45] This is driven by fears of global recession and rising inflation; energy security and supply concerns following Russia's invasion of Ukraine; and a decrease in global oil refining capacity. In its latest short-term energy outlook, the EIA forecasted oil prices to remain near current levels in 2023.[46] The EIA noted the possibility of continued supply disruptions and slower growth in oil production to potentially boost prices, however the potential for slower economic growth may dampen prices.

Figure 8: Perth diesel daily average terminal gate price

Source: Australian Institute of Petroleum, 2022, (online).

The ERA undertook the following approach to derive the reference diesel price for its analysis:

1. Derive the average daily Perth TGP over the preceding three months (August – October 2022).[47]

[45] US Energy Information Administration, 2022, *World Energy Outlook 2022 – Outlook for Liquid Fuels*, (online).

[46] US Energy Information Administration, October 2022, *Short-Term Energy Outlook*, (online).

[47] The WEM Rules require the diesel price input of the alternative maximum STEM price be based on the average of prices over "*the three months ending immediately before the month preceding the month in which the revised Alternative Maximum STEM Price takes effect*…". The analysis in this draft determination is based on prices as of November 2022 and therefore considers prices over the preceding three months. The reference distillate price will be updated with more recent data for the ERA's final determination.

2. Remove GST (10%) and diesel excise ($0.46/L) that would not be paid by local generators.[48]

3. Convert the cost of diesel from Australian cents per litre (ACPL) to $/GJ based on the estimated calorific content of diesel.

The outputs are shown in Table 3 below. For this determination, the ERA has relied on a reference diesel price of $34.1/GJ.

As noted above, this reference diesel price is used to cap the distribution of the delivered gas price (Figure 7) and derive the alternative maximum STEM price for the first month following the revised price limits taking effect (section 3.2). The price of distillate will vary due to fluctuations in world oil prices and refining margins. Over the coming year after the revised price limits take effect, AEMO will use prevailing average diesel prices to reset the alternative maximum STEM price every month using a formula determined by the ERA (section 3.2).

Table 3: Reference diesel price

Item	ACPL	$/GJ [a]
Perth TGP [b, c]	194.2	
TGP less GST	176.5	
TGP less GST and fuel excise[d]	130.5	**34.1**

(a) This analysis assumes 1 litre of diesel fuel is equivalent to 38.3 MJ.
(b) Australian Institute of Petroleum, 2022, Historical Diesel TGP Data, [retrieved on 4 November 2022], (online).
(c) The Perth TGP is based on the average of prices over the preceding three months (August – October 2022).
(d) Diesel excise is $0.460/litre from 29 September 2022. Australian Taxation Office, Excise duty rates for fuel and petroleum products, Item 10.10 – Diesel, [retrieved on 8 November 2022], (online).

2.4 Heat rate at minimum capacity

Heat rate is a measure of the efficiency of a generator in converting fuel into electricity. The heat rate is the amount of energy (GJ) used by a generator to generate one unit (MWh) of electricity. A lower heat rate implies the generator is more efficient at generating electricity. For gas turbines, the average heat rate decreases as the output level rises.

The WEM Rules require the heat rate to be determined at minimum capacity for the energy price limits determination, but do not define any method for determining this variable.[49] Consistent with its approach in the previous determination, the ERA determined the Parkeston units' average heat rate at minimum capacity by considering observed output levels closer to the Parkeston units' minimum stable generation level.[50] This ensures the average heat rate used in the calculation better reflects the high-cost conditions of the machines, which are typically expected to happen around the minimum stable generation of the units.

48 Australian Taxation Office, 2022, Excise duty rates for fuel and petroleum products, Item 10.10 – Diesel, [retrieved on 8 November 2022], (online).

49 Wholesale Electricity Market Rules, 1 September 2022, clause 6.20.7(b)(iii), (online).

50 Setting the price limits based on a heat rate that is substantially higher than minimum stable generation can result in generators not being able to recover their costs when they are required to run close to their minimum stable generation. When using historical dispatch information, it is important to consider that the calculation uses a reasonable minimum capacity distribution that is in line with the intention of the price limits.

The ERA has adopted the method from its previous determination to determine the heat rate at minimum capacity. The method is summarised as follows:

- Review the historical output level of the candidate machines to infer a distribution for the minimum capacity of the units that reflects the minimum stable generation of the units. This process is further explained in Appendix 2.
- Develop a distribution of minimum capacity by assuming the minimum capacity is normally distributed. The average of the distribution is comparable to the units' minimum stable generation level.
- Use the distribution of minimum capacity as an input into the heat rate curve provided by Goldfields Power to derive a distribution of heat rates at minimum capacity. The average of the distribution is used as an input in the energy price limits determination formula.

The mean of the distribution of the heat rate at minimum capacity is 20.3 GJ/MWh. This is lower than the mean heat rate at minimum capacity for Parkeston estimated in the ERA's previous determination (24.0 GJ/MWh). The reason underlying the decrease in average heat rate is due to the ERA relying on updated information regarding the Parkeston units' heat rate, which is discussed further below.

Updated information on Parkeston heat rate

As part of this determination, the ERA received two heat rate curves from Goldfields Power illustrating the Parkeston units' operation using gas and diesel respectively. The Parkeston units are more efficient at generating electricity using gas instead of diesel, resulting in a lower operating cost when operating using gas.

The ERA has used the best available source of information and relied on the updated gas-fuelled generation heat rate curve to determine the maximum STEM price, as this is the price limit that applies to gas-fuelled generators.

The resulting average heat rate at minimum capacity is 20.3 GJ/MWh.

2.5 Loss factor

The loss factor is calculated as the average marginal loss for power injected by a generator into the transmission network relative to a reference node. The SWIS currently has one reference node, the Muja 330 kilovolt (kV) bus-bar.[51]

A loss factor greater than one implies that more electricity is delivered to the reference node than what was injected into the transmission network. In general, loss factors increase with demand at a node and decrease with increasing generation at a node.

The WEM Rules require Western Power to annually determine the loss factor for each connection point in its network and provide these values to AEMO.[52] Western Power determined a loss factor of 1.1245 to apply from 1 July 2022.[53] This is lower than the loss

51 The reference node is defined as the Muja 330 kV bus-bar until the new WEM commencement day (which is currently proposed as 1 October 2023) and the Southern Terminal 330 kV bus-bar after the new WEM commencement day. Wholesale Electricity Market Rules, 1 October 2021, Chapter 11, "Reference Node", (online).

52 Wholesale Electricity Market Rules, 1 September 2022, clause 2.27, (online).

53 Western Power, 2022, *2022/23 Loss Factor Report*, p.9, (online).

factor that applied in 2021 (1.1322). A decrease in the loss factor will increase the price limits and vice versa (holding all other variables constant).

2.6 Risk margin

The risk margin is a measure of uncertainty in the assessment of the mean short run average cost of a 40 MW generator. The WEM Rules do not specify a method for calculating the risk margin.

The WEM Rules specify that, for the purposes of the formula in clause 6.20.7(b), the mean VOM cost, mean fuel cost and mean heat rate at minimum capacity are used to determine the mean average variable cost. As these variables are uncertain, the risk margin is used to account for their uncertainty.

The ERA generated distributions of the variable parameters in the calculation and determined a distribution for the short run average variable cost to calculate:

- The 80th percentile of the short run average variable cost distribution as the price limit.
- The difference between the mean and the 80th percentile of the distribution as the risk margin as illustrated in Figure 3 earlier.

The value of risk margin changes depending on the spread of the distribution calculated for the short run average variable cost. This is because the difference between the mean and the 80th percentile of the distribution can vary depending on the distribution spread.

3. Results

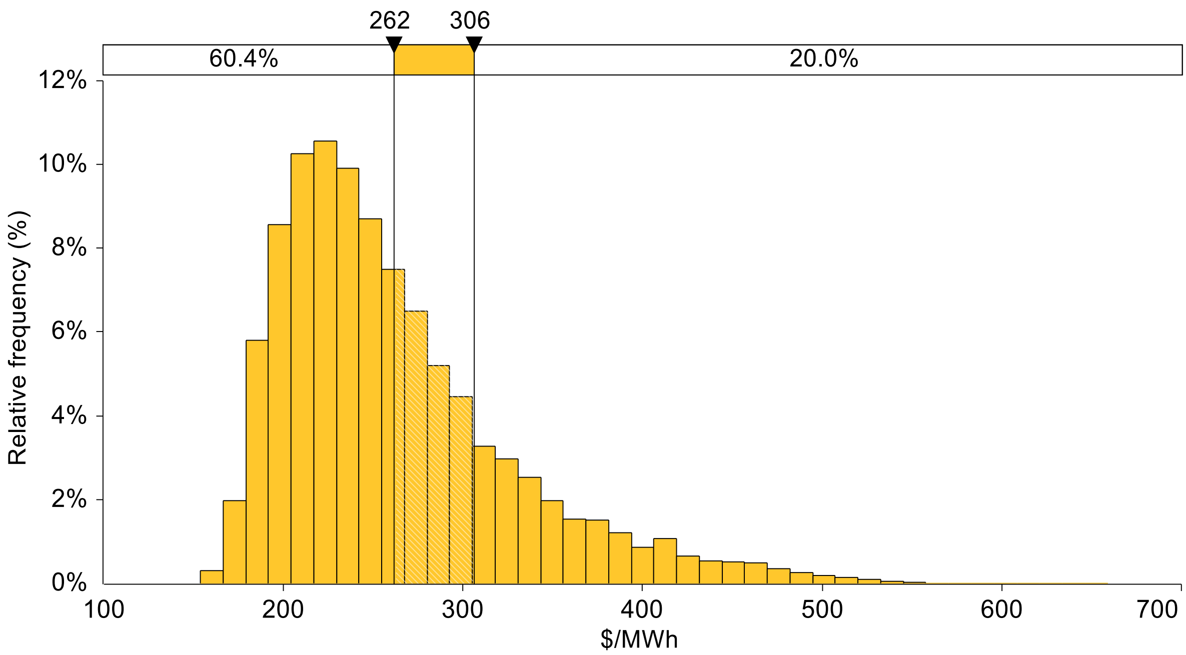
There is considerable uncertainty in the variables – such as the heat rate, fuel cost and VOM cost – that make up the formula to calculate the energy price limits. The ERA has generated probability distributions for each of the key input variables that are uncertain: fuel cost, heat rate and VOM costs. This was achieved by conducting Monte Carlo simulations to derive a probability distribution for the short run average variable cost of the candidate machines based on the inferred distribution for the uncertain variables.[54]

3.1 Maximum STEM price

Table 4 shows the estimates of the input factors and the revised maximum STEM price. Figure 9 shows the estimated distribution of the average variable cost for the Parkeston units, which this year is assessed as the highest cost generating works in the SWIS.

The proposed maximum STEM price is $306/MWh.

Figure 9: Average variable cost distribution, Parkeston units



Note: The two vertical markers indicate the mean and 80th percentile respectively of the distribution.

54 Monte Carlo simulation is a statistical technique that allows for risk in quantitative analysis and decision making. 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. Monte Carlo simulation does thousands of times (iterations), and the result is a probability distribution of possible outcomes. In this way, Monte Carlo simulation provides a much more comprehensive view of what may happen. It explains not only what could happen, but how likely it is to happen.

Table 4: Calculation of the maximum STEM price, Parkeston units

Component	Unit	Proposed value: 2022	Determined value: 2021
Mean variable O&M cost	$/MWh	40.1	30.1
Mean heat rate at minimum capacity	GJ/MWh	20.3	24.0
Mean fuel cost	$/GJ	12.3	10.1
Loss factor	-	1.1245	1.1322
Average variable cost distribution – Mean	$/MWh	258.9	241.6
Average variable cost distribution – 80th percentile	$/MWh	303.8	289.7
Risk margin	%	17.0	19.5
Maximum STEM price	**$/MWh**	**306**	**290**

Note: Revised values of the calculation components may not result in the maximum STEM price calculated above due to rounding.

The following differences are observed when comparing the price limits proposed this year to the price limits determined last year:

- The estimated mean VOM cost for the Parkeston units ($40/MWh) is higher than the previous determination ($30/MWh). This is largely due to a decrease in the average dispatch duration observed over shorter dispatch cycles. This was explained in section 2.2.
- The estimated mean fuel cost component of the calculation is greater than the estimate in the previous determination. This is largely due to an increase in estimated gas prices, as the average price of gas used this year ($6.70/GJ) is larger than that used last year ($5.04/GJ). This was explained in section 2.3.

3.2 Alternative maximum STEM price

As per the requirements of the WEM Rules, each month, AEMO resets the alternative maximum STEM price according to changes in the price of distillate. This requires an indexation formula as shown below:

$$alternative\ maximum\ STEM\ price = non\text{–}fuel\ component + (fuel\text{–}component \times fuel\ price)$$

A linear equation is derived to determine the alternative maximum STEM price as a function of the net ex-terminal distillate price. To derive the linear equation several values for the alternative maximum STEM price are determined based on variation in the distillate price. The calculation of the alternative maximum STEM price uses the same model as that used for the estimation of the maximum STEM price. A linear regression is then applied using the sampled distillate price as the independent variable and the sampled alternative maximum STEM price as the dependent variable. This method is summarised below:

1. Use the same model developed for the estimation of maximum STEM price.[55]

2. Use a range of distillate prices as fuel costs to input to the model.

3. Determine the alternative maximum price as the 80th percentile of the estimated distribution for the average variable cost of the highest cost generator.

4. Run a linear regression analysis on the range of distillate prices used as the independent variable and the estimated alternative maximum STEM price as the dependent variable to determine fuel and non-fuel components.

5. The slope of the regression line reflects the fuel coefficient of the indexation formula. The intercept reflects the non-fuel coefficient of the indexation formula.

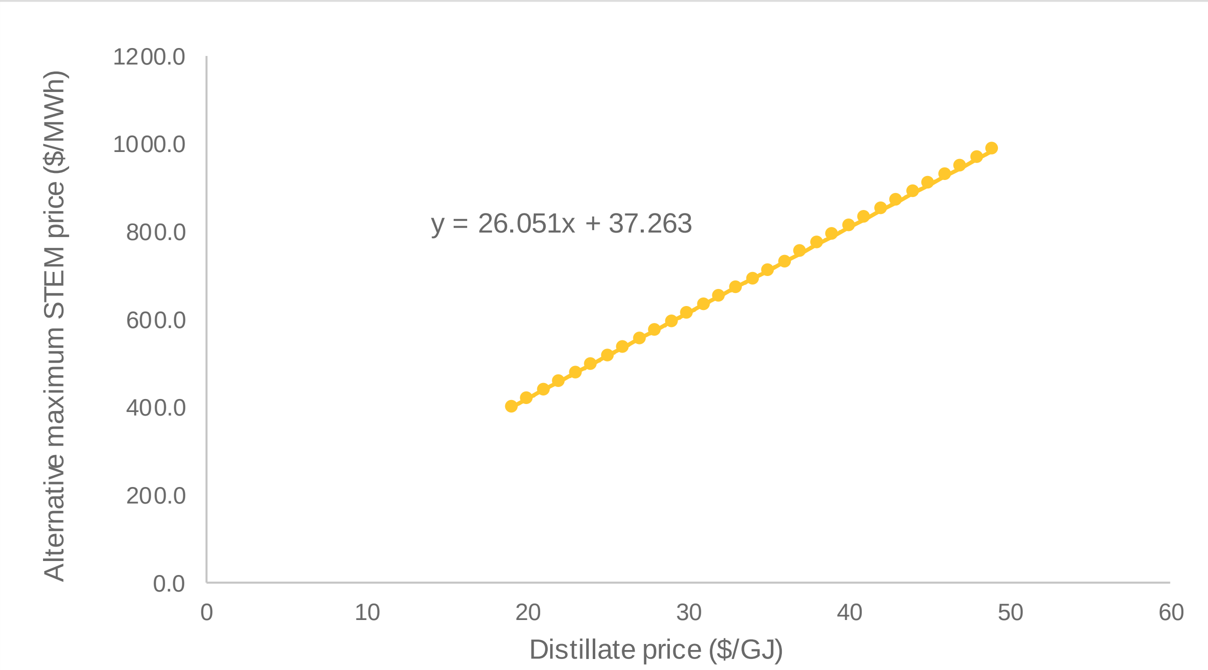
The revised indexation formula for the alternative maximum STEM price is below:

- $alternative\ maximum\ STEM\ price = 37.263 + 26.051\ \times\ diesel\ price\ (\$/GJ)$

The estimated regression function is shown in Figure 10.

At the current distillate price of $34.1/GJ, the ERA's revised indexation formula yields a higher value for the alternative maximum STEM price of $926/MWh, when compared to $898/MWh, based on the formula determined last year.[56]

Figure 10: Proposed alternative maximum STEM price based on range of distillate prices, Parkeston units



55 The exception to this is the heat rate at minimum capacity input. As explained in section 2.4, the ERA received a heat rate for the Parkeston units' operation using diesel. This diesel-fuelled heat rate was used in determining the regression equation for the alternative maximum STEM price. The average heat rate at minimum capacity, as an input to this calculation, is 24.3 GJ/MWh.

56 The indexation formula determined last year was 33.627 + 25.426(*d*) where *d* is the prevailing diesel price. ERA, 2022, *Addendum to the energy price limits final determination*, (online).

Appendix 1 The ERA's gas price forecast

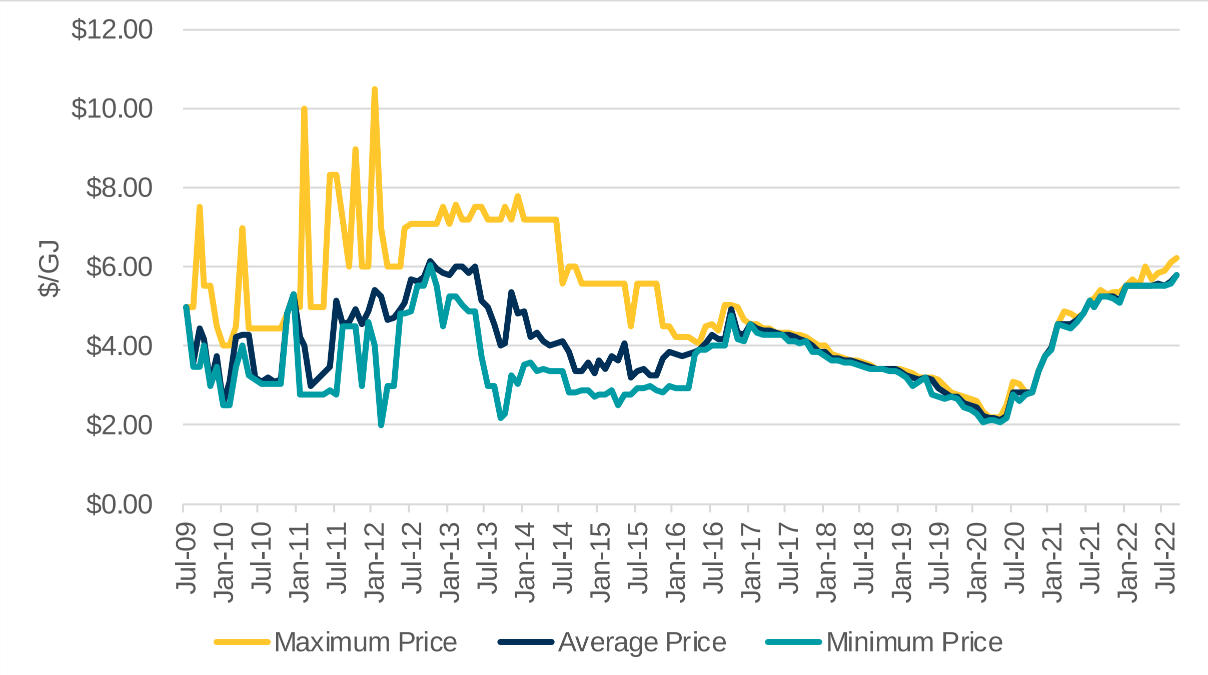
The ERA considered two data sources for the price of natural gas in Western Australia to forecast the opportunity cost of using gas for electricity generation for the Parkeston units over the planning period:[57]

- Maximum monthly gas prices on the gasTrading platform.[58]
- Quarterly, volume weighted average prices of gas published by DMIRS.

Both data sources have limitations in explaining the opportunity cost of using gas for electricity generation. For example, the gas price data from gasTrading that forms the basis of the ERA's forecast is based on the spot trading of gas. Prices observed on the platform can be sensitive to small increases in demand and/or supply on the platform and may not reflect the opportunity cost of sourcing larger volumes of gas on a firm access basis. The ERA considered these possible limitations when developing its forecast.

Figure 11 shows the historical maximum, average and minimum prices for the gasTrading spot market.

Figure 11: Historical gas price for trades in the gasTrading spot market



Source: gasTrading Australia (online).

57 The opportunity cost of using gas for electricity generation is the value of the best alternative use of gas. For example, a generator might sell its acquired gas instead of using it for generating electricity if it earns a higher value from the sale of gas.

58 The gasTrading platform acts as an agent for the sellers of gas and operates a spot market. Each successful bidder receives gas based on its bid price, such that the market does not clear at a single price. Each month the platform provides an indication of the quantity of gas available for sale over the next month and invites buyers to bid for the quantity of gas they require for each day over the next month. The platform then accepts the highest bid prices until all available volumes of gas are allocated. See: gasTrading Australia Pty Ltd, 2022, *Historical Prices and Volumes*, (online).

Between November 2021 and September 2022, each month, the platform has traded between 266 TJ and 546 TJ through the spot market. As of 15 October 2022, the platform was on track to trade over 415 TJ of gas for the month of October 2022.[59]

The platform also facilitates trades that are not on the spot market, including:

- Off market trades, which are ad hoc 'firm' and 'as available' contracts spanning from 1-day to multiple years.[60] As of 15 October 2022, the platform was on track to trade over 1,100 TJ off market for the month of October 2022.[61] Price information for off market trades is not publicly available.
- Backup gas trades, for which a gas price is published for buyers that didn't participate in the bidding round, to indicate the price that gasTrading Australia can secure gas for and make available within the month. Volume information for backup gas trades is not publicly available. The most recent backup price, for October 2022, was $6.60/GJ.[62]

Based on information available on the gasTrading platform, the traded gas on the spot market is interruptible, with supply curtailments applying to the lowest price purchases first.[63] Given the order of access to gas through the platform, the highest bid price can be considered as a reasonable proxy for the price of firm access to gas. Accordingly, in the previous determination, Jacobs used the historical maximum monthly spot price to produce a forecast of future gas prices for determining the energy price limits.

Minimum or average monthly prices on the gasTrading platform might reflect the opportunity cost of acquiring gas from the market, however, it is doubtful that supply arrangements around the spot market at average or minimum spot prices is reliable or comparable to a firm supply of gas. Nevertheless, over the past year the difference between the maximum and minimum spot price has been relatively low, with an average of only $0.24/GJ.

The price for backup gas trades on the gasTrading platform may better represent the opportunity cost of gas, reflecting the cost of supplying additional gas to meet demand when gas from the spot market is unavailable. Time series analysis of historical back up prices from March 2018 to October 2022 produced a naïve forecast, which is a horizontal forecast of backup prices based on the most recent actual price ($6.60/GJ) and the standard deviation of the historical back-up price time series of $1.35/GJ.[64]

The gasTrading spot market may not be a liquid market. One indication of possible illiquidity of the platform is the volume of trades, which have been only a small proportion of the gas use for electricity generation in the SWIS and overall gas use in Western Australia.[65] As shown

[59] gasTrading Australia, 2022, October 2022 – Invitation, (online), [accessed 8 November 2022].

[60] AEMO explains firm supply of fuel as fuel supply or transportation that is underpinned by contractual rights to specified volumes (which may be flexible or subject to the Market Participant's nomination) and the conditions on those volumes (e.g., take or pay). For supply to be firm, the obligation to supply must be binding on the supplier and must not be interruptible (after allowing for planned and unplanned outages) or sold on an as-available (spot) basis. AEMO, 2020, Market procedure*: certification of reserve capacity, version 9.0* , p. 5, *(online).*

[61] gasTrading Australia, 2022, October 2022 – Invitation, (online) [accessed 8 November 2022].

[62] gasTrading Australia, 2022, October 2022 – Historical prices and Volume (online) [accessed 8 November 2022].

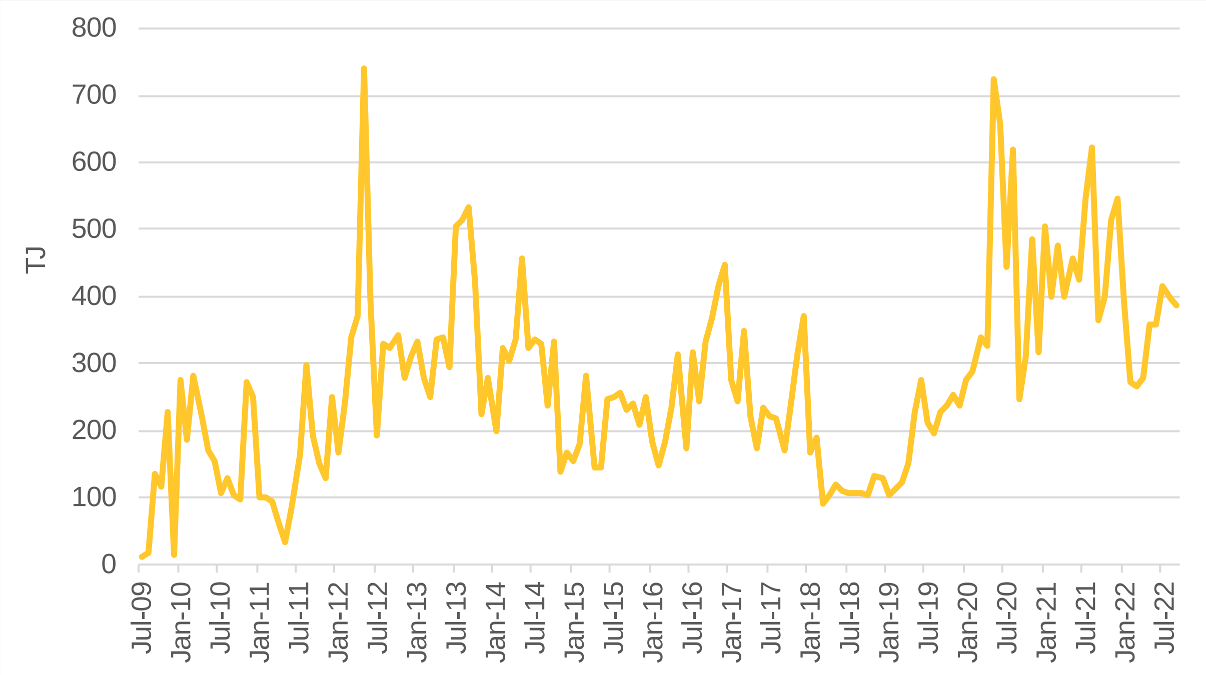
[63] gasTrading Australia, 2022, Spot market – How it works, (online) [accessed 8 November 2022].

[64] Time series analysis of historical back up prices from March 2018 to October 2022 produced an ARIMA (*0,1,0*) model.

[65] No single measure can sufficiently explain the level of liquidity in a market. Volume of trades is an indicator of liquidity and cannot provide a reliable measure of liquidity. An assessment of liquidity typically involves the study of measures such as number of trades, open interest, volume of trades, price volatility, and market

in Figure 12, the monthly quantity of gas traded in the gas trading spot market has never exceeded 750 TJ.

Figure 12: Historical monthly quantity of gas traded in the gasTrading spot market



Source: gasTrading, Spot Market – Historical Prices and Volume, (online), accessed 8 November 2022.

For comparison, since 2015, the monthly average consumption of gas in Western Australia has roughly been between 30,562.16 TJ and 32,322.55 TJ.[66]

It is not clear to what extent current spot prices could change if demand for or supply of gas in the gasTrading spot market increased. For example, an increase in demand for firm access to gas might increase prices in the market as bidders seeking firm access increase their bid price to minimise the likelihood of supply interruption. Therefore, historical spot prices and forecasts produced based on the observed spot market prices have limitations in reflecting the market price of gas.

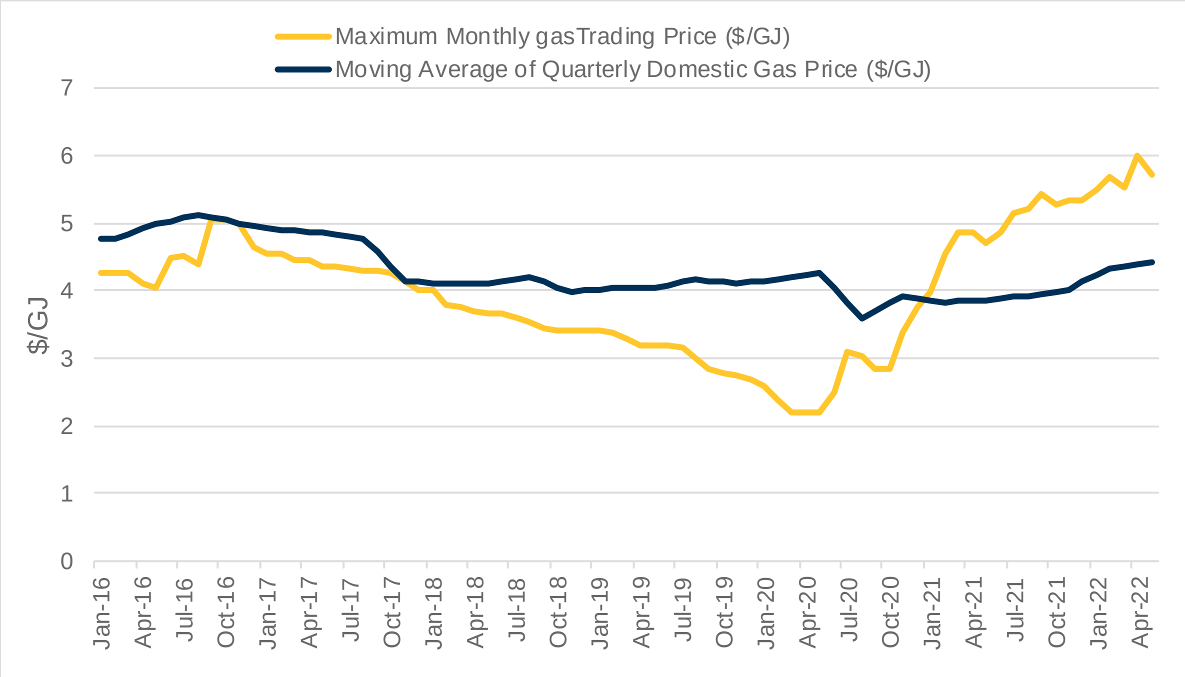
In the 2020/21 review of the energy price limits, Synergy, Alinta Energy and the Australian Energy Council raised concerns that gasTrading spot prices were not representative of the true fuel costs faced by generators, given the possibility for interruption of supply and illiquidity of the market.[67] This was particularly a concern because, at the time, gasTrading monthly maximum spot prices were substantially below the average prices published by DMIRS. This pattern of pricing has continued to the present. The moving average of quarterly, volume weighted average domestic gas prices published by DMIRS and monthly maximum spot prices published by gasTrading Australia are depicted in Figure 13.

impact measures. For example, refer to Sarr and Lybek, 2002, *Measuring liquidity in financial markets*, International Monetary Fund, (online).

[66] AEMO, 2021, WA Gas Statement of Opportunities, 2021 WA GSOO figures data register, December 2021, (online) [accessed 9 November 2022].

[67] ERA, 2020, *2020 Energy price limits decision*, pp. 27-28, (online).

Figure 13: Moving average of quarterly, volume weighted average DMIRS domestic gas prices and maximum monthly gasTrading spot prices



Source: DMIRS (online) and gasTrading (online).

DMIRS' quarterly price series represents the volume weighted average of gas prices by producers, not maximum prices. This price series is heavily weighted by bilateral contract prices, some of which are expected to be for firm gas supply but does not include any information on bilateral sales between non-producers.[68] The DMIRS price data also excludes any domestic gas sales not subject to the State royalty regime, such as domestic gas projects in Commonwealth waters and certain LNG facilities.

For the gas price forecast in the previous determination period, the ERA engaged a consultant (Jacobs) to develop a forecast of gas prices. Jacobs considered the risk of using DMIRS data to project the future gas price, given the prevailing and expected conditions in the gas market at the time, and the possible lag in reflecting those conditions due to the use of quarterly data. Jacobs explained that in 2021 spot gas prices had risen above DMIRS average prices, as shown in Figure 13. Given the expected lag in DMIRS prices, Jacobs considered the use of DMIRS data could result in under-forecasting gas prices over the ensuing 12 months.

Jacobs concluded that the use of spot gas prices for forecasting was more appropriate because:

- If the spot market was illiquid, then observed prices reflected the lower boundary for the opportunity cost of gas.
- Spot prices better reflected current market conditions.
- Spot price volatility was larger than that for DMIRS historical prices, contributing to a larger prediction band in projecting future gas prices, which can better address the risk of underestimating price limits.

[68] The domestic gas price published by DMIRS is an average derived from the actual total value of domestic gas sales divided by the actual total volume of domestic gas sales reported to DMIRS for the calculation and payment of royalties under the State royalty regime. The published prices do not include any transport costs, other downstream costs, or any mark-up paid by customers to wholesalers.

The ERA considers that Jacob's considerations are still relevant. Additionally, the ERA's analysis of market conditions suggests that gas prices may increase over time, rather than remain static. Accordingly, the ERA employed the gasTrading data to forecast future gas prices for the energy price limits determination.

Time series forecast modelling of gas prices

Maximum monthly gas prices for the period July 2009 to August 2022 were extracted from the price history table on the gasTrading Australia website.[69] The 158 maximum monthly prices ranged between $2.20/GJ and $10.50/GJ, with a mean of $5.13/GJ and a standard deviation of $1.61/GJ.

The maximum monthly gas prices in the first three years of the market were characterised by major volatility, which has not been seen to reoccur since, and was probably the result of market commencement. Accordingly, data from January 2013 to July 2022 only was selected for use in the time series forecast modelling of future gas prices. This resulted in the data set comprising 127 maximum monthly prices, ranging between $2.20/GJ and $7.80/GJ, with a mean of $4.95/GJ and a standard deviation of $1.50/GJ. Z-score standardisation of the maximum monthly gas prices produced values between -1.8 and 1.9, indicating that there were no outliers in the data.[70]

The best ARIMA model fitting the data had one level of differencing, with 1 autoregressive and 1 moving average lagged error term. This model was run to produce forecast differences with 95 percent prediction intervals for the planning period i.e., September 2022 to July 2023. Diagnostics indicated the presence of outliers in the data. Z-score standardisation of the differenced data revealed outliers in July 2014, June 2015, July 2015, and November 2015. These outliers were replaced with the mean of the differenced data, and the model was rerun. The forecast price differences and prediction intervals for the original and outlier adjusted data were then used to calculate the maximum monthly gas prices for this period. Given the closeness in values produced by the original and outlier adjusted data, the forecasts from the original data were selected for use in the energy price limits determination (see Figure 5, in the main body of this report).

Forecast maximum monthly gas prices ranged between $6.23/GJ for September 2022 and $7.20/GJ for July 2023, with a mean of $6.70/GJ and a standard deviation of $0.32/GJ.[71]

[69] gasTrading Australia Pty Ltd Spot Market Data, Historical Prices and Volume (online) [accessed 2 November 2022]

[70] Z-score standardised values of less than -3 and greater than 3 can be classed as outliers.

[71] Notably, the maximum monthly price for September 2022 on the gasTrading website is $6.25/GJ and the minimum price is $5.80/GJ. These values are very consistent with the values predicted by the model for September 2022, which were a maximum monthly price of $6.23/GJ, with a lower bound of $5.83/GJ.

Appendix 2 Operational characteristics of the Parkeston units

This appendix details the ERA's analysis underlying its modelling of the costs of the Parkeston units to determine the maximum STEM price as noted in the main body of this report.

Background

The calculation of VOM costs requires a forecast of dispatch cycle characteristics for the candidate machines over the review period – generally, the next 12 months.

Consistent with the approach developed in previous determination of the price limits, the characteristics of dispatch cycles over the planning period are forecast based on the observed dispatch of candidate machines in recent years. The ERA also considered information provided by Goldfields Power to inform the modelling.

Dispatch cycles are modelled through the following variables:

- The sampled number of starts per year, $n_{s,i}$.
- The sampled run time between 0.5 and 4 hours, d_i, expressed in hours.
- The sampled dispatch cycle capacity factor as a function of run time, $cf_i(d_i)$, expressed as a percentage.
- Maximum capacity, q_{max}, expressed in MW.

where index i indicates a sampled dispatch cycle. The analysis samples a total of $I = 10{,}000$ dispatch cycle costs through a Monte Carlo simulation.

Capacity factor is defined as (**Equation A3.1**):

$$cf = \frac{g}{q_{max} \times d}$$

The product of sampled maximum capacity, dispatch cycle duration and capacity factor yield a sample for the energy generated, g_i, (expressed in MWh per dispatch cycle) during the sampled dispatch cycle i. This product is then used to convert the start-up cost expressed in dollar per start, $SC_{per\ start}$, to a start-up cost denominated in dollar per MWh energy generated, $SC_{per\ MWh}$.

It is important the Monte Carlo simulation draws samples for the above variables from distributions that reasonably reflect the future operation characteristics of the candidate machines during the planning period.

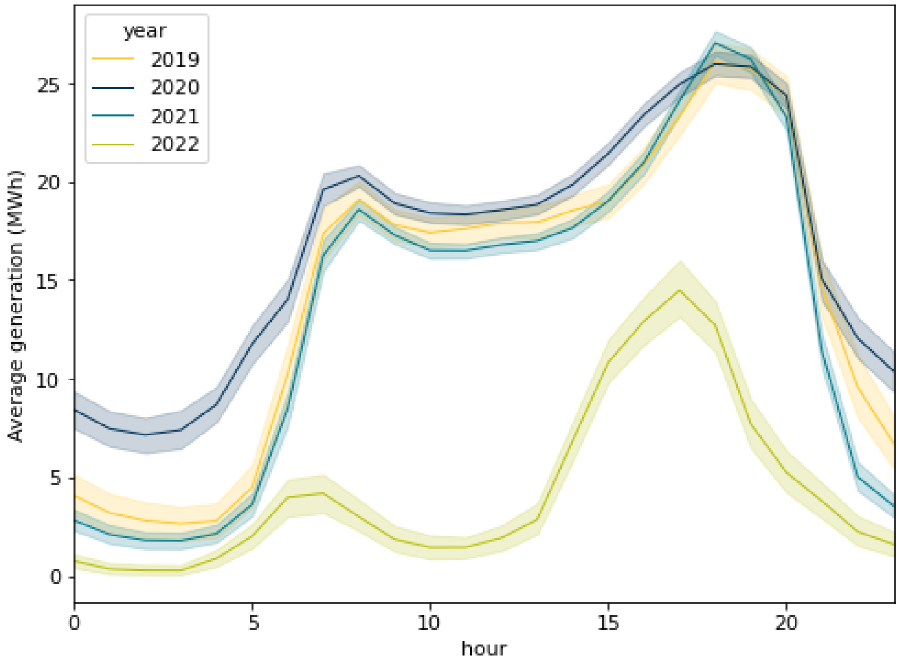
The analysis of dispatch cycle characteristics considered the observed dispatch of Parkston units between 1 August 2019 and 31 July 2022, and information received from the operator of these units. This choice of historical data was based on information received from the asset operator who considered that the past three years better reflect the future operation of these units.

Operating activity over all dispatch cycles

The daily profile for the average output of Parkston units is depicted in Figure 14. The chart shows a substantial decrease in the average output of these units across all hours in 2022 compared to previous years.

As shown in Figure 14, the units generally provide the greatest average dispatch quantity in the evening peak demand hours, consistent with the observation that the Parkeston units usually operate as a peaking generator. This trend has continued in 2022, however the quantity of dispatch has decreased below that observed in the prior years. This observation is consistent with Goldfields Power's advice.

Figure 14: Average generation per hour of day, Parkeston units



Source: ERA's analysis based on SCADA data.

(a) The 2019 and 2022 samples do not cover complete years (Aug – Dec 2019; January to August 2022) as the analysis considers data over the past 3 years to August 2022.

(b) Shaded areas show the 95 per cent confidence interval for the average output.

The ERA's analysis considered the entire sample of observed dispatch since 2019 to forecast the future dispatch cycle characteristics. This accounts for the possibility of observing the same level of variation in start-up count and energy generation profile over the future years as that observed since 2019. This decision was also informed by information provided by Goldfields Power.

The analysis of Parkeston dispatch cycles since 2019 showed that:

- The average duration of all dispatch cycles was greater than the corresponding value for Pinjar.
- The average generation per dispatch cycle was greater than the corresponding value for Pinjar.
- A portion of all dispatch cycles observed were short dispatch cycles. This is substantially lower than the corresponding ratio for Pinjar units. The observed dispatch contained

dispatch cycles as short as 0.5 hours. This is not unexpected as Goldfields Power advised that Parkeston may, at times, be dispatched only for a single trading interval, as it is a peaking generator.

Average duration of short dispatch cycles

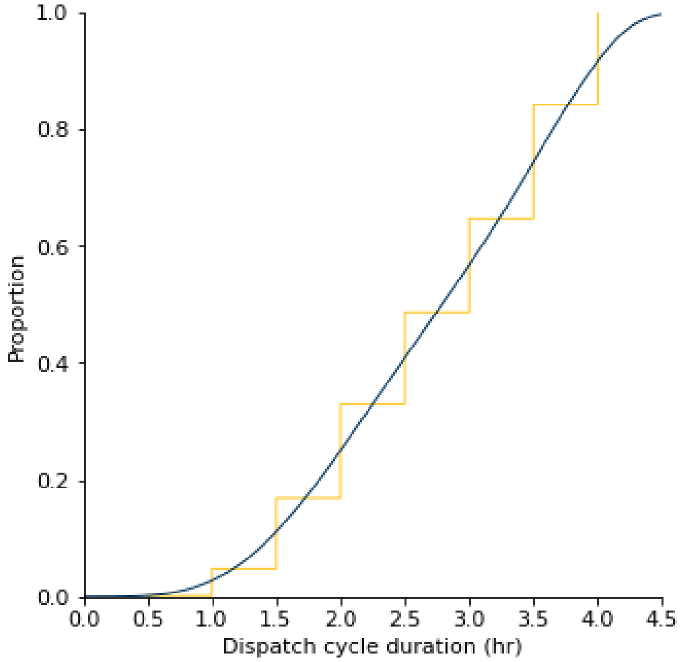
As explained earlier, the analysis considers short dispatch cycles instead of all dispatch cycles to ensure the estimated VOM cost is spread over relatively short dispatch run times and the estimated cost reflects the high-cost operating conditions of the machines. The model samples from the distribution of duration for short dispatch cycles between 0.5 and 4 hours.

The ERA observed a substantial decrease in the annual average duration of all dispatch cycles in 2022 compared to previous years.

The model samples from the empirical distribution of short dispatch cycle duration, smoothed by a kernel-density estimate.[72] The empirical short dispatch cycle duration for Parkeston units is presented in Figure 15.

The average duration of dispatch over short dispatch cycle duration is 2.6 hours. The lower and upper bound for this distribution are set to 0.5 and 4.0 hours. This is presented in Figure 16.

Figure 15: Empirical cumulative distribution, duration of short dispatch cycles, Parkeston units

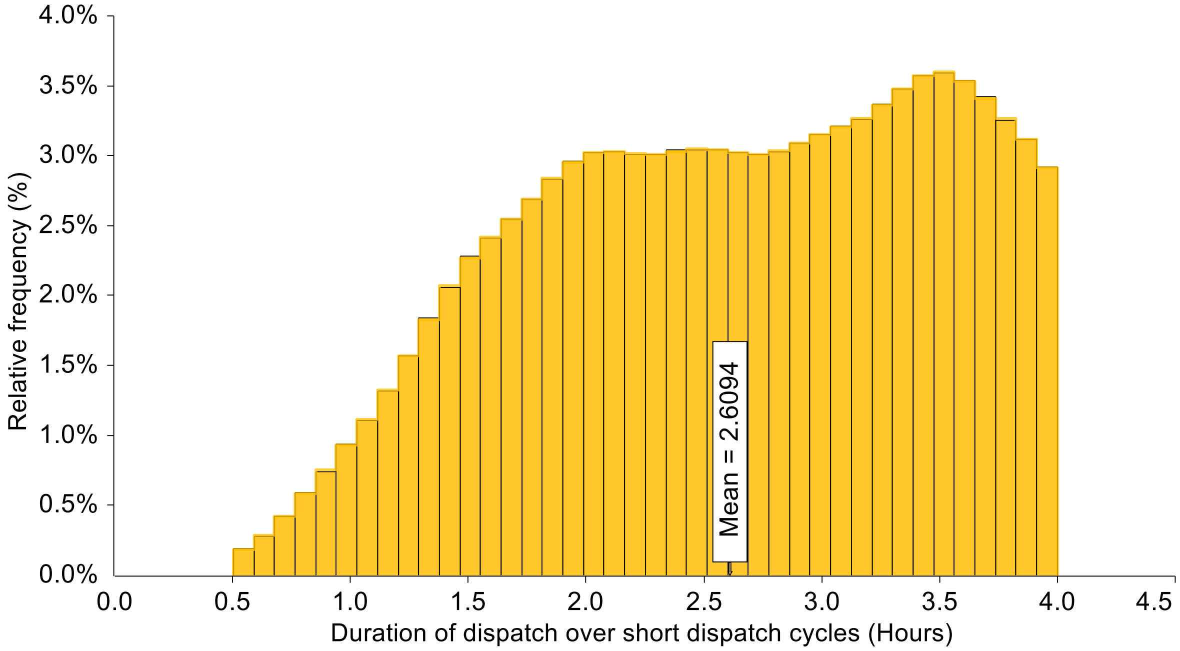


Source: ERA's analysis based on SCADA data provided by Goldfields Power.

Note: the teal step curve shows the empirical cumulative distribution of dispatch cycle duration. The grey line shows the cumulative kernel-density estimate of the empirical distribution.

[72] Kernel density estimation allows for estimating the probabilities associated with each dispatch cycle duration by smoothing the observed empirical distribution.

Figure 16: **Distribution of dispatch duration over short dispatch cycles, Parkeston units**



Source: ERA analysis based on SCADA data provided by Goldfields Power.

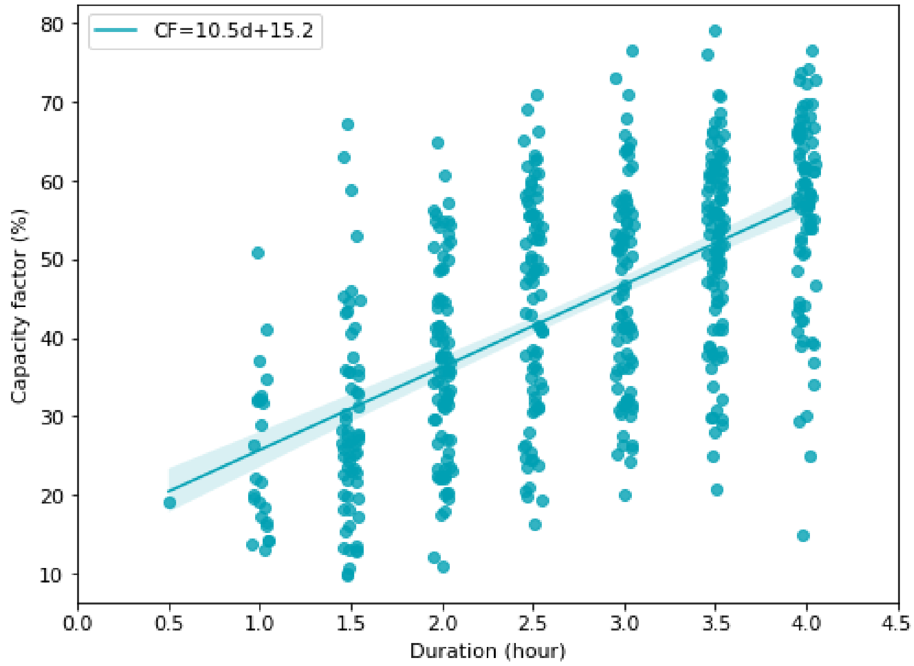
Average capacity factor over short dispatch cycles

The model accounts for the relation between the expected energy generated from different levels of dispatch cycle duration. This relation is captured by analysing the historical short dispatch cycles for Parkeston. Figure 17 depicts the expected capacity factor over a dispatch cycle as a function of dispatch cycle duration, derived from the historical dispatch of the units.

The model uses the linear line fitted to the historical data to determine the expected capacity factor subject to the sampled run time over short dispatch cycles for the Parkeston units. The model then randomly samples from the residuals of the fitted line, subject to run time, and adds the residual sampled to the expected capacity factor, determined based on the regression line.

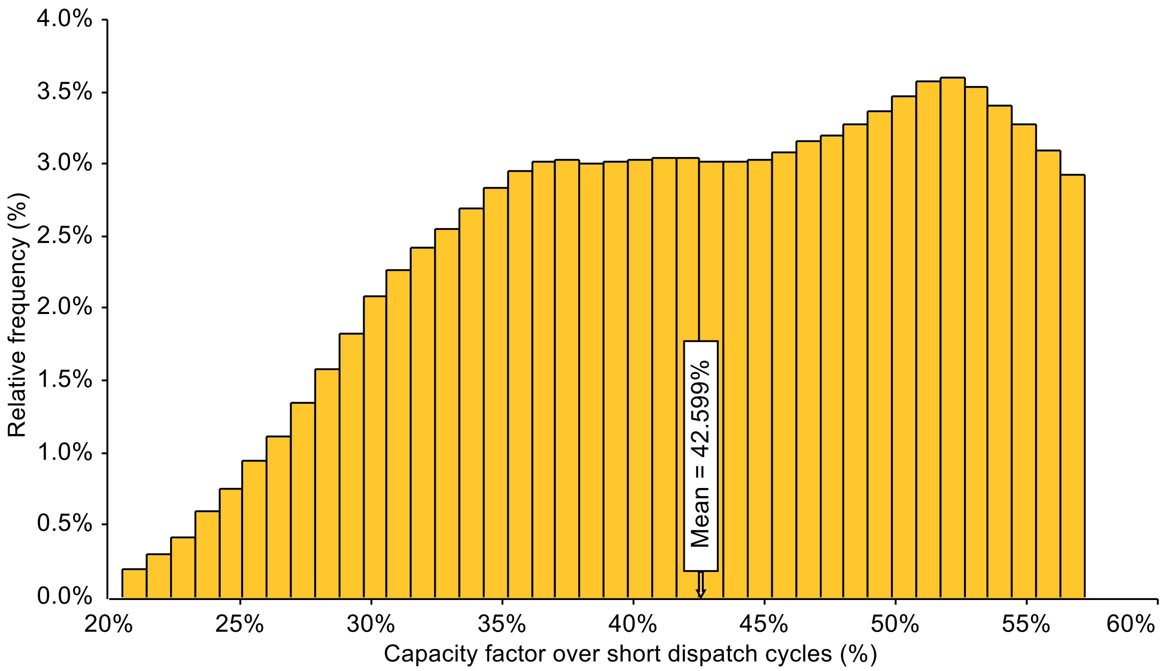
The resulting distribution of capacity factors over short dispatch cycles is presented in Figure 18. The average capacity factor of short dispatch cycles is 42.6 per cent, which is lower than 49.2 per cent in the ERA's previous determination. A key driver of this change is the decrease in duration of short dispatch cycles from six hours to four hours, and the observed decrease in dispatch duration of the units.

Figure 17: Relationship between dispatch cycle duration and capacity factor, short dispatch cycles, Parkeston units



Source: ERA's analysis based on SCADA data provided by Goldfields Power.

Figure 18: Distribution of capacity factor over short dispatch cycles, Parkeston units



Source: ERA analysis based on confidential data provided by Goldfields Power.

Maximum capacity

This review uses a constant maximum capacity in the calculations for the Parkeston units. This is based on Goldfields Power's expectation of the Parkeston units' operational experience and the OEM's recommendation.

The analysis does not assume a distribution of maximum capacity because accounting for seasonal variation in maximum capacity creates additional computational steps with no benefit. As explained in the previous section, the sampling of dispatch duration is from the empirical distribution of dispatch duration and capacity factor. Any variation in maximum capacity is already captured in the empirical distributions used.

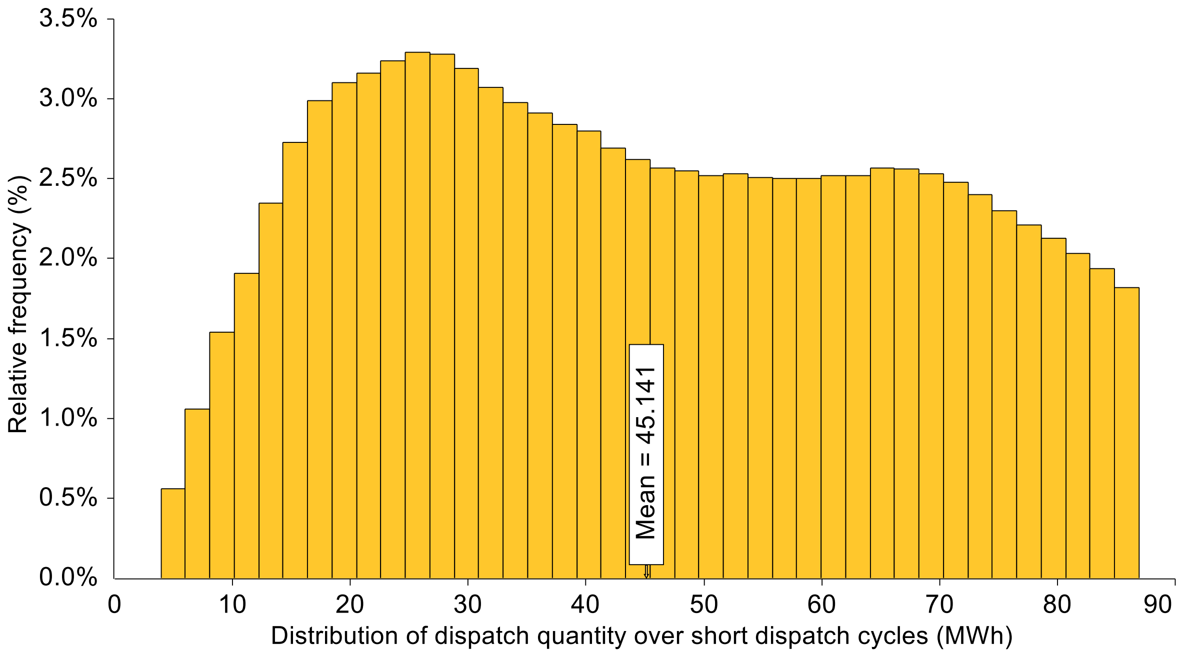
Average generation over short dispatch cycles

As explained earlier, the analysis considers short dispatch cycles, instead of all dispatch cycles, to derive VOM costs on a $/MWh basis. This ensures the estimated VOM cost is spread over relatively short dispatch run times and the estimated cost reflects the high-cost operating condition of the machines. This requires an estimate of dispatch generation (MWh) over short dispatch cycles.

To derive a distribution of dispatch generation over short dispatch cycles, the ERA considered the product of the units' dispatch duration (hours), maximum capacity (MW) and capacity factor over short dispatch cycles. The product of these three variables yields the amount (MWh) of electricity generated per start of the machine. The whole distribution, not just the average of the distribution, of each of the three variables is used to derive a distribution of electricity generated per start of the machine.

The average amount of energy generated over short dispatch cycles is approximately 45.1 MWh. This is presented in Figure 19 below.

Figure 19: Distribution of dispatch quantity over short dispatch cycles, Parkeston units



Source: ERA analysis based on confidential data provided by Goldfields Power.

Minimum capacity

The WEM Rules specify that the heat rate is to be determined at minimum capacity. Typically, the heat rate of gas turbines increases with an increasing rate as the output level of these machines decreases, making the operation of the plants less efficient. The calculation of heat rate at the minimum capacity level ensures the calculated price cap covers for the extremely high-cost conditions of the machines.

The WEM Rules do not specify how to determine the minimum capacity of the candidate machines. Gas turbines can operate at very small output levels for short periods of time. However, inefficiency and mechanical stress during low output periods makes the low output operation infeasible for long durations. For stable operation, these units must meet at least a minimum output level. Consistent with its method to estimate minimum capacity in its previous determination, the ERA considered the Parkeston units' observed output level during short dispatch cycles as a percentage of the maximum capacity of the units.

The ERA's analysis considered the observed output level of Pinjar during short dispatch cycles as a percentage of the maximum capacity of the units. Figure 20 shows the cumulative empirical distribution of the output level of Parkeston units observed between 2019 and 2022.

The data used in the analysis is recorded in half-hourly format. This makes the estimate of the output level of the machines during the first and last trading interval in each dispatch cycle unreliable. This is because it is not known over what period the recorded energy was generated. To address this issue, the ERA excluded the first and last trading intervals in each dispatch cycle when determining the output percentage of the units. This ensured the analysis of the observed minimum output of units would not be distorted by unreliable numbers estimated for the first and last trading intervals for each dispatch cycle.[73] This is consistent with the approach adopted in the ERA's previous determination.

As shown in Figure 20, the minimum capacity of the units observed is approximately 7 per cent of the maximum capacity. The probability of observing output levels below 7 per cent is negligible. Half of the observed dispatch levels are below 75 per cent.

Consistent with the approach in the ERA's previous determination, this analysis uses the first 10 percentiles of the empirical distribution for the Parkeston units' output level. Using the first 10 percentiles of the distribution provides a distribution for minimum capacity for which the mean is reasonably close to the minimum stable generation limit for Parkeston.

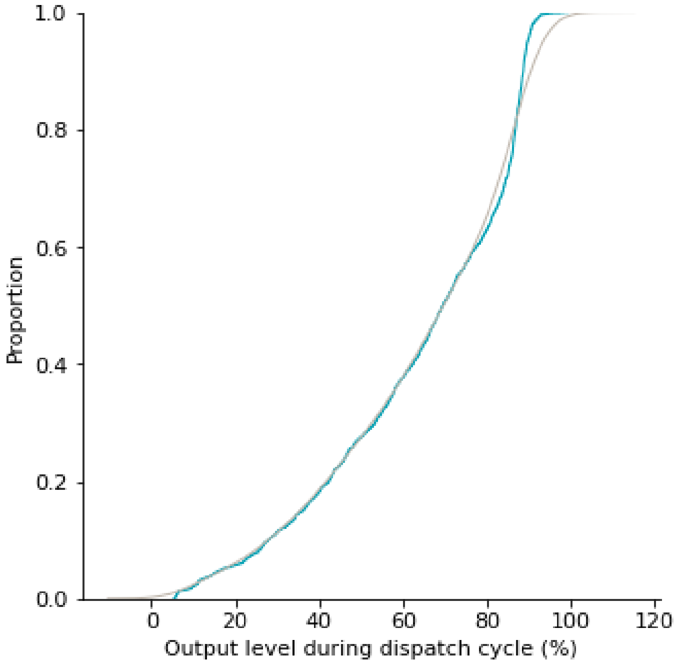
The fitted normal distribution for minimum capacity has a mean of 21 per cent of maximum capacity and standard deviation of 9 per cent of maximum capacity. The lower and upper bound for this distribution is set to 7 per cent and 48 per cent of maximum capacity, respectively. This is largely consistent with the distribution parameters in the previous determination.

The resulting distribution of the Pinjar units' minimum capacity has an average of 8.3 MW. This is largely comparable to the units' minimum stable generation level.

The distribution of minimum capacity is input into the heat rate curve provided by Goldfields Power to derive a distribution of heat rates at minimum capacity (Figure 21). The resulting average heat rate at minimum capacity is 20.3 GJ/MWh.

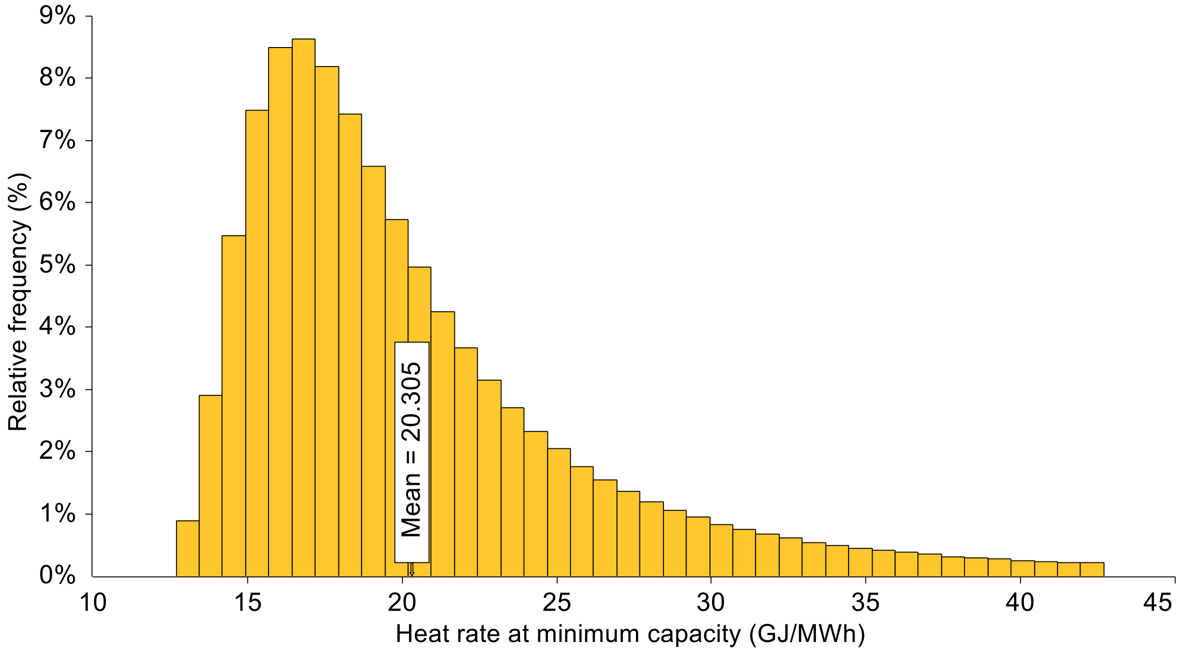
[73] The analysis also excluded any trading interval with less than one MWh output. This was to minimise the likelihood of recording error to distort results.

Figure 20: Empirical cumulative distribution for output level (capacity factor) reached during short dispatch cycles, Parkeston units



Source: ERA's analysis based on confidential data provided by Goldfields Power.

Figure 21: Distribution of heat rate at minimum capacity, Parkeston units



Source: ERA analysis based on confidential data provided by Goldfields Power.

Appendix 3 Energy price limits based on the Pinjar units

This appendix presents the results of analysis for the Pinjar units and compares it to the base calculations for Parkeston units presented in section 3. Each of the components of the energy price limits calculation – VOM cost, fuel cost, heat rate, loss factor – as determined for the Pinjar units are presented below.

Modelling results

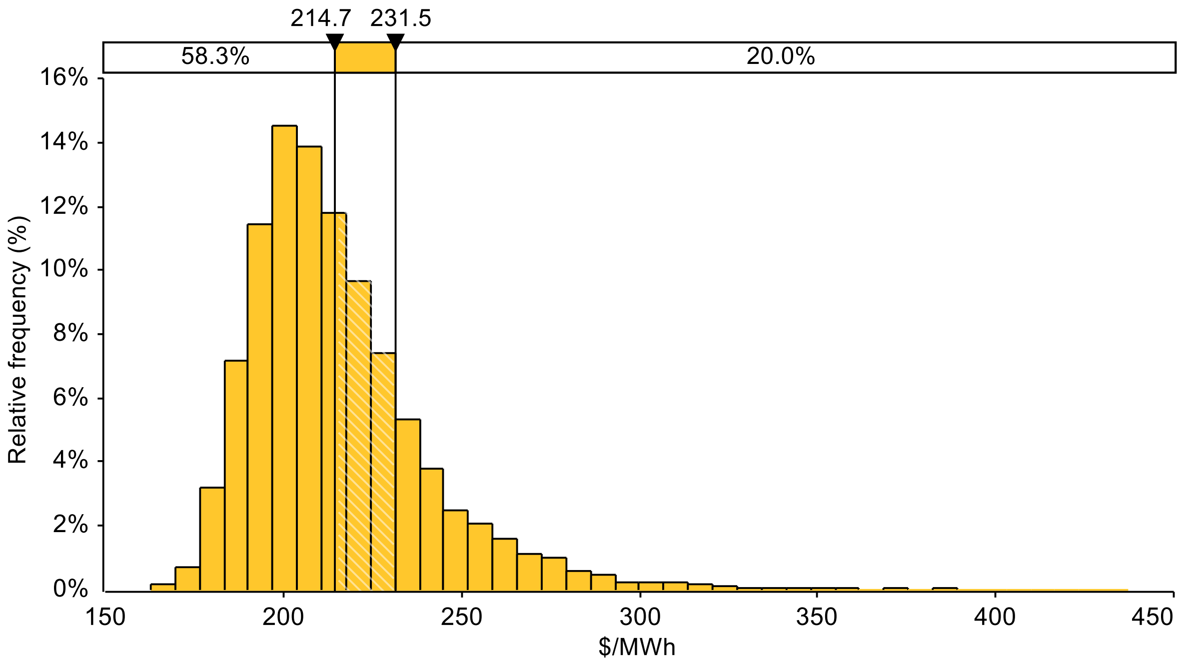
Assessed maximum STEM price

Figure 22 shows the estimated distribution of the average variable cost for Pinjar. The maximum STEM price assessed for the Pinjar units is $231/MWh compared to $306/MWh assessed for the Parkeston units. The Pinjar units do not set the maximum STEM price as the Parkston units' assessed price is higher.

Table 5 outlines the changes in the underlying parameters of the energy price limits calculation based on the Pinjar units.

The changes in the assessed components of the formula are presented in Figure 23 below. The biggest driver in the increased assessment of the Pinjar units' cost is the increase in the fuel cost component, which is caused by in an increase in delivered gas prices, as forecast by the ERA.

Figure 22: Average variable cost distribution, Pinjar units



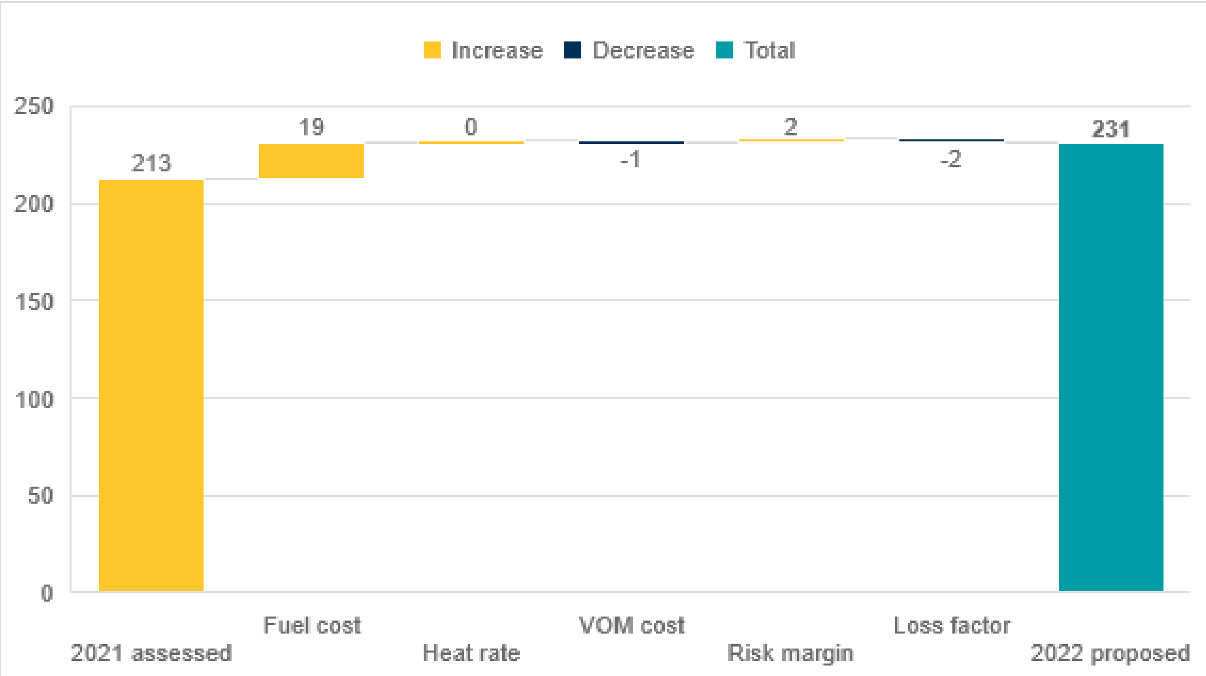
Note: The two vertical markers respectively indicate the mean and 80th percentile of the distribution.

Table 5: Calculation of the maximum STEM price, Pinjar units

Component	Unit	Assessed – 2022	Assessed – 2021
Mean variable O&M cost	$/MWh	39.5	40.2
Mean heat rate at minimum capacity	GJ/MWh	21.5	21.5
Mean fuel cost	$/GJ	8.4	7.6
Loss factor	-	1.0323	1.0229
Mean of the average variable cost distribution	$/MWh	216	198
80th percentile of the average variable cost distribution	$/MWh	231	213
Risk margin	%	8	7
Assessed maximum STEM price	**$/MWh**	**231**	**213**

Note: Calculated values may differ due to rounding.

Figure 23: Change in components of the assessed maximum STEM price based on the Pinjar units



Note: Totals may not add due to rounding.

Assessed alternative maximum STEM price

Based on the Pinjar units, the indexation formula for the alternative maximum STEM price is:

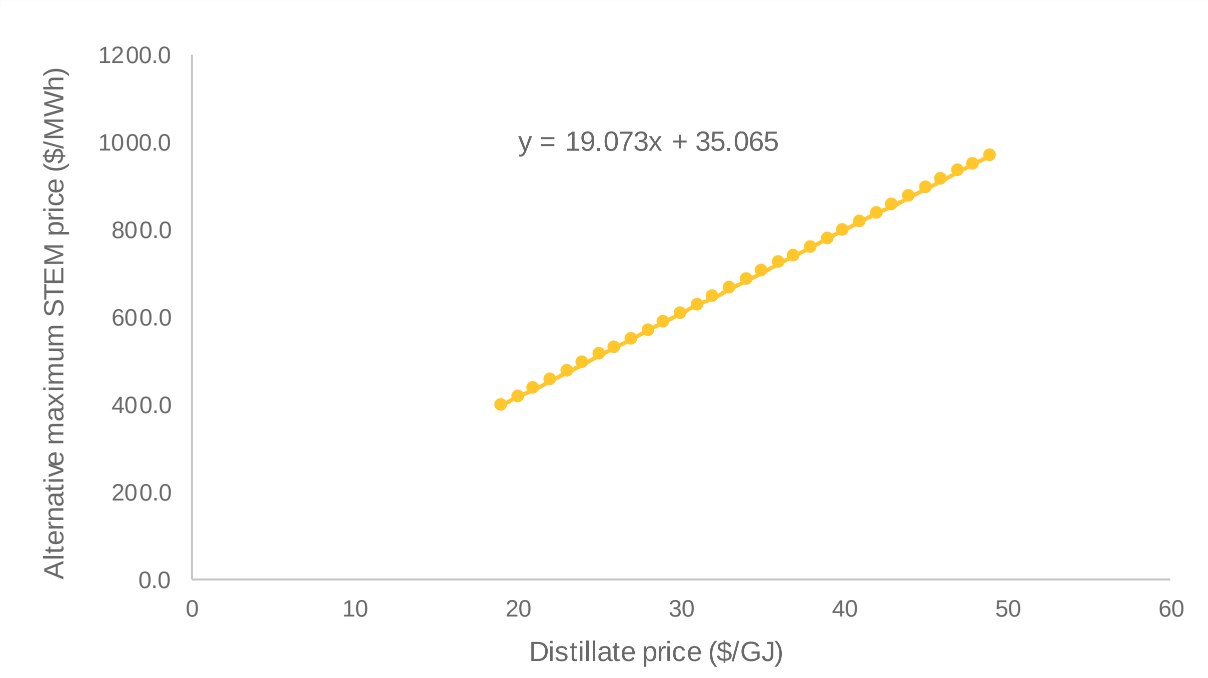
$$alternative\ maximum\ STEM\ price = 35.065 + (19.073 \times diesel\ price\ (\$/GJ))$$

The method for deriving the above formula is explained in section 3.2.

Assuming a distillate price of $34.1/GJ, the assessed alternative maximum STEM price for the Pinjar units is $685/MWh (Figure 24), compared to the price assessed for the Parkeston units as $926/MWh (section 3.2).

The Pinjar units do not set the alternative maximum STEM price as the Parkston units' assessed price is higher.

Figure 24: Proposed alternative maximum STEM price based on a sample of distillate prices, Pinjar units



Calculation parameters

The ERA's analysis and results for the Pinjar units' VOM cost, fuel cost, heat rate, loss factor are presented below.

VOM cost

For the Pinjar units, the ERA estimates an average VOM cost per start, which was comprised of start-up fuel consumption costs and maintenance costs. These costs are converted to VOM costs on a $/MWh basis using the method explained in section 2.2.2.

For the review this year, the mean VOM cost for Pinjar is $39.5/MWh, which is comparable with the estimate of $40.2/MWh in the ERA's previous determination. The estimation method and main factors used are summarised in Table 6.

Key changes since the ERA's previous determination include:

- An increase in underlying maintenance costs. Synergy provided its estimated maintenance costs, which were identical to costs provided for the ERA's previous determination but escalated for inflation using Synergy's forecast CPI.
- An increase in discount rate used to discount maintenance costs due in future periods to present value. This has the biggest effect on reducing the resulting VOM cost.
- An increase in start-up fuel consumption cost, driven by an increase in average delivered gas prices. This is discussed further below.
- A decrease in average dispatch generation (MWh) to spread VOM costs and derive VOM costs on a $/MWh basis, driven by the change in duration of the length of short dispatch cycles.

Table 6: Parameters underlying estimate of average VOM cost, Pinjar units[74]

Item	Unit	Value	Notes
Average maintenance cost (levelised cost per start)	$/start	[redacted]	
Average start-up fuel consumption	$/start	[redacted]	
Average duration of dispatch over short dispatch cycles	Hours	[redacted]	Average duration of dispatch duration is sampled from a distribution dispatch duration over short dispatch cycles.
Average quantity of dispatch over short dispatch cycles	MWh	[redacted]	Average quantity of energy generated over short dispatch cycles is sampled from a distribution of short dispatch cycles.
Average capacity factor as a function of dispatch duration over short dispatch cycles	%	[redacted]	Average capacity factor is estimated based on sampled distribution of capacity factors over short dispatch cycles.
Mean VOM cost	**$/MWh**	**39.5**	

Source: ERA analysis of confidential data provided by Synergy.

VOM cost component 1: Start-up fuel consumption cost

Synergy provided the quantity of gas that the Pinjar units require to start. Based on an average delivered gas price of $8.4/GJ, the ERA developed a distribution of start-up fuel consumption costs.[75]

74 The values redacted in this table are based on confidential information provided to the ERA.

75 The ERA's determination of the delivered gas price for the Pinjar units is discussed further below in this appendix.

VOM cost component 2: Variable maintenance costs

The ERA received Synergy's estimate of VOM costs for the Pinjar units, expressed per start of the units. Synergy also provided the maintenance expenditure costs that underpinned its estimate of VOM costs.

The ERA's approach to develop the Pinjar units' maintenance cost as a VOM cost per MWh requires an estimate of a 'levelised' cost for turbine maintenance expenditures across the operating life of the unit. A unit operator would be able to recover its maintenance expenditure by including the levelised cost in its offers to the energy market. The ERA used Synergy's estimate of underlying cost components of the Pinjar units' maintenance expenditures. This was conducted in two steps:

1. The timing of expected future maintenance expenditures is identified based on the expected number of starts.

2. The present value of maintenance expenditures is calculated and is divided by the present value of the number of starts.

The above steps provide a 'levelised' cost per start. This estimation method is explained in the stylised example below.

Stylised example for the calculation of VOM cost per start

This example calculates levelised variable maintenance costs for Pinjar based on data available from a previous review of the price limits in 2015.[76] For clarity, the calculation of the price limits in this review uses estimates of maintenance expenditures as provided by Synergy, which differs from the values used in this stylised example.

The Pinjar units have a maintenance schedule as listed in the table below. The overhaul cost for each maintenance type is also listed in the table as estimated by AEMO's consultant in 2015.

Table 7: Estimated maintenance schedule, Pinjar units, 2015

Overhaul type	Number of starts to trigger overhaul	Cost per overhaul (2015 Dollars)
A	600	1,348,773
B	1200	4,517,420
A	1800	1,348,773
C	2400	4,138,774
Total		**11,353,739**

Depending on the number of factored starts per year, n_{fs}, the above maintenance expenditures occur in future periods. Assuming that the machine has just recently been under maintenance type C and a number of starts per annum, n_s, equal to 65, the cash flow profile of future maintenance expenditures is shown in Table 8.[77] For this example, each start of the machine is on average expected to contribute to 1.07 factored starts for maintenance type A ($MF_A = 1.07$) and 0.68 factored starts for maintenance type B and C ($MF_{B/C} = 0.68$).

For simplicity, this example shows a full maintenance cycle schedule that ends with the maintenance type C.

Table 8: Cash flow profile of future maintenance expenditure

			Year										
Maintenance type	**Maintenance factor, MF**	**Factored starts per year, n_{fs}**	**1**	**…**	**9**	**…**	**26**	**…**	**28**	**…**	**44**	**…**	**55**
A	1.07	70			A_1		A_2				A_3		
B	0.68	44							B				
C	0.68	44											C

An increase in the frequency of starts can increase the number of required maintenance events during the remaining life of the machine and bring those expenditures closer in time. That is, an increase in the frequency of starts increases the present value of future maintenance expenditures. The present value of the cash flow profile shown in Table 8 is estimated based on a real discount rate of 5 per cent per annum:

Present value for expenditure A_1: $PV_{A_1} = \frac{\$1{,}348{,}773}{(1+0.05)^9} = \$869{,}431$

Present value for 65 actual starts per year for 9 years: $PV_{65,t=9} = 462\ starts$

The present value of future maintenance expenditures A_1 is then divided by the discounted number of starts over the remaining life of the asset to estimate a levelised cost per start.

Levelised cost for expenditure A_1: $LC_{A_1} = \frac{PV_{A_1}}{PV_{65,t=9}} = \$1{,}882\ per\ start$

If the generator recovers $1,882 each time it starts the machine, it would be able to recover its maintenance expenditure A_1 by the time it becomes due on year nine. This is because the generator expects to recover $65 \times \$1{,}728$ per year over nine years, for which the present value is equal to $869,431.

The total levelised maintenance cost, LC_{total}, in this example is the sum of levelised costs for all expected maintenance expenditures:

$$LC_{total} = LC_{A_1} + LC_{A_2} + LC_{A_3} + LC_B + LC_C$$

The calculation of VOM cost is to account for the expected remaining life of the plant and exclude expenditures that are not likely to occur before the expected end of life of the generator. The calculation is also to account for uncertainty in the number of future starts.

A Monte Carlo simulation can be developed to account for uncertainties in the number of starts per annum (or any other variable factor), and to derive a distribution for total levelised maintenance costs per start.

The levelised cost per start is converted to a discounted cost per MWh of electricity generated, based on the possible duration of short dispatch cycles. As explained earlier, the analysis considers short dispatch cycles to ensure the estimated cost per start is spread over a shorter period, and hence, the estimated cost per unit of energy generated reflects the very high-cost operating conditions of the units. This conversion approach is the same as that used for Parkeston, as explained in section 2.2.2. For Pinjar, the conversion method uses parameters based on the observed operation of Pinjar over the past five years. The derivation of these parameters is explained in detail further below in this appendix.

Review of underlying maintenance costs

Similar to the approach adopted in previous reviews of the price limits, the ERA considered variable maintenance costs in its analysis, which are the cost of conducting periodic

76 Jacobs, 2015, *Energy price limits for the Wholesale Electricity Market in Western Australia – Final report*, Table 3-4, (online).

77 The original equipment manufacturer applies a factored starts to estimate the timing of maintenance as opposed to actual starts of the machine. General Electric, 2021, *Heavy-Duty Gas Turbine Operating and Maintenance Considerations*, GER-3620P (01/21), (online), pp. 35-36.

maintenance work required to maintain the generating unit in an efficient and reliable condition. These costs mainly comprise maintenance service, parts and labour expenses.

According to GE, the turbine manufacturer of both Pinjar and Parkeston gas turbines, there are many factors – such as dispatch cycle run time, power setting, fuel, and site environmental conditions – that influence equipment life.[78] GE has developed a maintenance planning method that accounts for these factors and specifies maintenance schedules based on the number of 'factored' starts (or factored hours, as applicable).[79]

Each actual start of the unit contributes to the number of factored starts depending on operating conditions, as specified by GE. Some dispatch conditions put more mechanical stress and wear on turbines than other dispatch conditions and bring forward maintenance works. Others might put less stress on the turbine than a baseline operating condition. Future maintenance work that is required can be planned having consideration for historical operating data.

The VOM costs for the Pinjar units are driven by the number of starts. This is because the Pinjar units typically run for short periods of time when started.[80] According to GE's maintenance planning method, different maintenance works become due after the specified number of factored starts (or factored hours, as applicable). A full maintenance cycle is as below for gas turbines like Pinjar:[81]

- combustion inspection (type A) at 600 factored starts
- hot gas path inspection (type B) at 1,200 factored starts
- combustion inspection (type A) at 1,800 factored starts
- major overhaul (type C) at 2,400 factored starts.

Synergy provided the ERA with its maintenance costs in 2022 dollars for each of the maintenance intervals listed above. These costs are consistent with the costs provided to the ERA in its previous determination but escalated for inflation.[82] The ERA considered the cost items comprising each of the maintenance intervals and excluded non-variable costs.[83]

78 General Electric, 2021, *Heavy-Duty Gas Turbine Operating and Maintenance Considerations*, GER-3620P (01/21), (online), pp. 35-36.

79 This planning method is based on expected operation of turbines and can be reviewed and adjusted as specific operating and mechanical status data becomes available.

80 For Parkeston units, hours of operation are the main driver of maintenance costs because these units are designed to start and stop regularly.

81 GE's manual also advises a replacement of rotor after 5,000 factored starts. Given the expected number of starts for Pinjar, rotor replacement is expected to happen very far into the future in a maintenance cycle. The present value of cost related to rotor replacement is negligible and therefore calculations in this paper exclude this cost item. Previous reviews of the price limits also excluded rotor replacement costs.

82 Australian Bureau of Statistics, September 2022, Consumer Price Index Australia, Item 6401.0, series ID A2325826V, [retrieved on 28 October 2022], (online).

83 For example, Synergy included certain costs that were due on a yearly basis. These costs are fixed and will accrue regardless of the level of dispatch activity; therefore, the ERA considers these costs are not variable and are excluded. Some of the maintenance costs include a fixed proportion of costs. The ERA has similarly excluded the fixed proportion of costs and the cost of rotor replacement. Given the expected number of starts for the Pinjar units, rotor replacement is expected to happen very far into the future in a maintenance cycle. The present value of cost related to rotor replacement is negligible and therefore calculations in this paper exclude this cost item.

Estimation of discounted cost per start

Maintenance stages occur after a specific number of 'factored' starts or running hours, whichever comes first. Therefore, the cost for each start of the machine is accrued in a future period (i.e. when a maintenance stage actually occurs). When offering to the energy market, the operator accounts for these expected costs in the future. The operator plans for recovery of these costs before a maintenance event is due by spreading those expected costs over its offers to the energy market.

The ERA considered a reasonable way to spread those maintenance costs is to 'levelise' those costs per each start of the machine. A levelised cost is a constant cost that the operator includes in its offers to the energy market to fully recover its VOM costs before those expenditures are due. This is the present value of expected future maintenance costs divided by the present value of the expected number of starts (or number of hours, as applicable) before a maintenance is due. Ideally, the present value of future maintenance expenditures is estimated based on:

- a discount rate
- the current status of the asset in terms of the last maintenance performed
- the average number of starts per year.

This estimation yields an average discounted cost of starts during the remaining life of the asset.

The calculation of VOM costs in this review used:

- The method explained above assuming a full maintenance cycle with a duration determined by the expected number of factored starts per year.[84]
- A real pre-tax weighted average cost of capital (WACC) of 6.01 per cent per year, to estimate the present value of expected variable maintenance expenditure.[85] The analysis assumes variable maintenance expenditures remain constant in real terms over future periods.
- A normal distribution for modelling the number of starts with a mean of 61.2 starts per year. The maintenance factors used are 1.07 for maintenance type A and 0.68 for maintenance type B and C, consistent with the previous determination.

Fuel cost

The ERA determined a distribution for delivered gas prices for the Pinjar units after considering:

- Synergy's current and expected delivered fuel costs, provided confidentially to the ERA.

[84] For example, based on an expected 53.1 starts per year the maintenance type C occurs in year $\frac{2400}{0.68\times 53.1} = 67$. A simulation iteration with 53.1 starts per year estimates VOM costs assuming a 67-year remaining life.

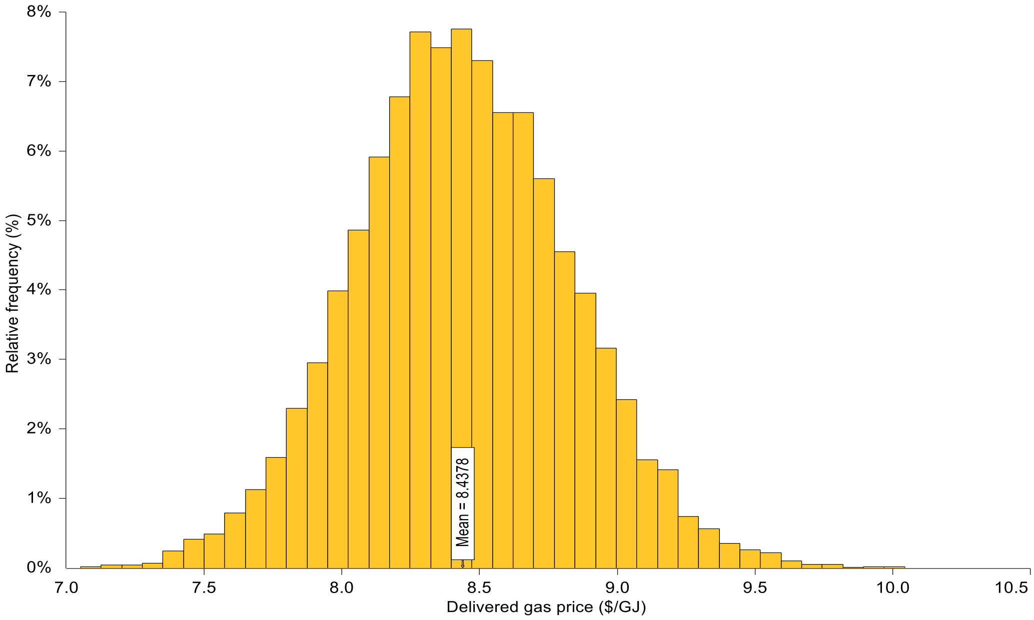
[85] The calculation of real WACC considered an average inflation forecast of 2.2 per cent per annum using the Reserve Bank of Australia's estimated inflation rate, applied to a nominal WACC of 8.3 per cent estimated by the ERA. For the inflation forecast, see: RBA, October 2022, *Average annual inflation rate implied by the difference between 10-year nominal bond yield and 10-year inflation indexed bond yield*, series ID GBONYLD, (online). For the nominal WACC, see: ERA, 2022, *2023 benchmark reserve capacity price for the 2025/26 capacity year – Draft determination*, p. 10 (online).

- Any arrangements Synergy has in place to procure gas, provided confidentially to the ERA.
- The ERA's forecast of gas prices over the coming year based on spot prices from the gasTrading platform, estimated at an average of $6.70/GJ (undelivered), as explained in section 2.3.1.
- The ERA's estimated distribution of gas transmission costs to the Pinjar units based on the reference tariffs for the minimum spot price expected on the pipeline, which had an average of $1.545/GJ.[86]

The resulting average of the distribution of the delivered gas price for the Pinjar units is $8.4/GJ, which is higher than the mean fuel cost of $7.6/GJ, estimated in the 2021 review.

The resulting distribution of delivered gas prices is presented in Figure 25.

Figure 25: Distribution of delivered gas prices, Pinjar units



Source: ERA analysis

Heat rate

The ERA received two heat rates curves from Synergy – for Pinjar A (units 1 and 2) and Pinjar B (units 3, 4, 5 and 7).

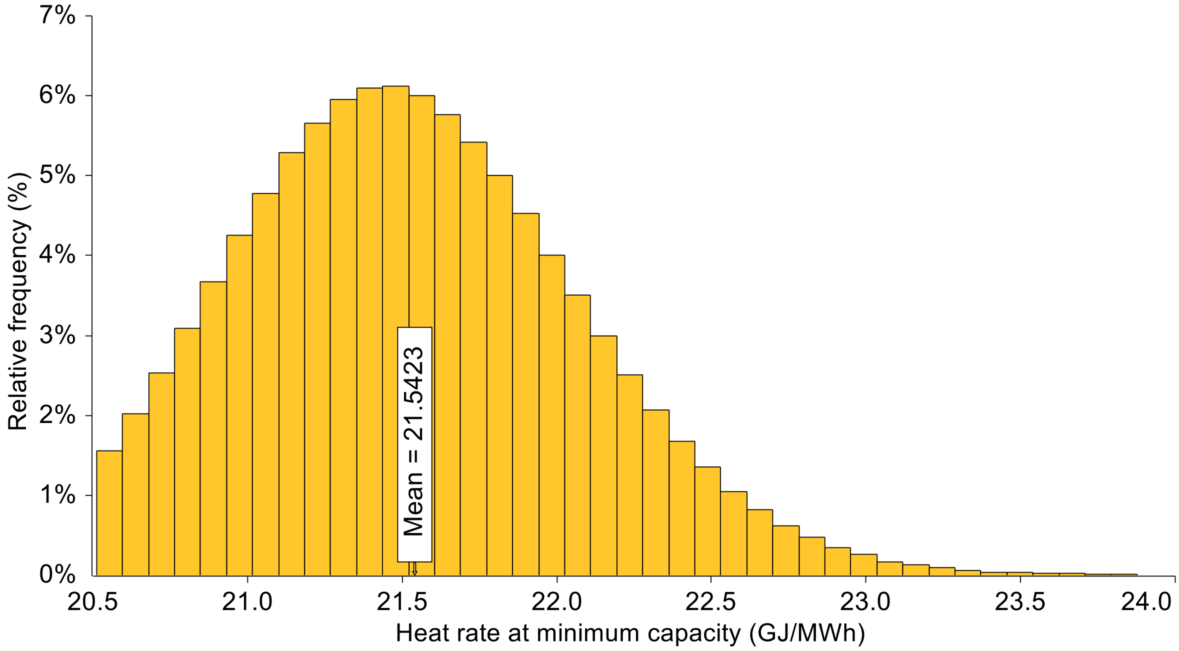
86 Gas is delivered to the Pinjar units on the Dampier to Bunbury Natural Gas Pipeline (DBNGP). The tariff for delivery on the pipeline is determined by negotiation between the pipeline operators and gas shippers. TO account for the uncertainty in transport costs, the ERA has assumed a distribution of gas transport costs based on the spot capacity on the pipeline., Spot capacity is defined as gas transmission capacity that is available for purchase on a gas day. The minimum bid price for daily bids for spot capacity cannot exceed 115 per cent of the base T1 tariff. Based on the current T1 reference tariff ($1.343/GJ), the ERA has estimated the minimum spot price as $1.545/GJ and used this value as the average of its distribution of gas transport costs. The ERA assumed the minimum spot price for full haul on the DBNGP is normally distributed with an average of $1.545/GJ and a standard deviation of $0.15/GJ. This method is consistent with the ERA's approach in the previous determination. At the time of this report's publication, the reference tariffs that apply from 1 January 2023 had not been published. The updated reference tariffs will be considered for the ERA's final determination.

The ERA's method for determining the heat rate at minimum capacity was explained in section 2.4. The key difference in the analysis between the Pinjar and Parkeston units is that the ERA received two heat rates for each of the Pinjar A and Pinjar B units. The ERA chose the higher of the two heat rate distributions provided by Synergy (for the Pinjar A and Pinjar B machines), as this would result in a higher resulting energy price limit determination. This is consistent with the ERA's approach, as outlined in section 2, to consider using an input value, among the range of possible values, that would provide a higher price cap to ensure that generators can sufficiently recover their costs.

Based on the analysis of the Pinjar units' output level, the model assumes the minimum capacity for Pinjar is normally distributed, with a mean of 10.3 MW and a standard deviation of 0.6 MW. The average of the distribution is comparable to the units' minimum stable generation level. This is explained further below in this appendix.

The mean of the distribution of the heat rate at minimum capacity is 21.5 GJ/MWh. This is unchanged from the mean heat rate at minimum capacity estimated in the ERA's previous determination (21.5 GJ/MWh) and is presented in Figure 26.

Figure 26: Distribution of heat rate at minimum capacity, Pinjar units



Source: ERA analysis of confidential data provided by Synergy.

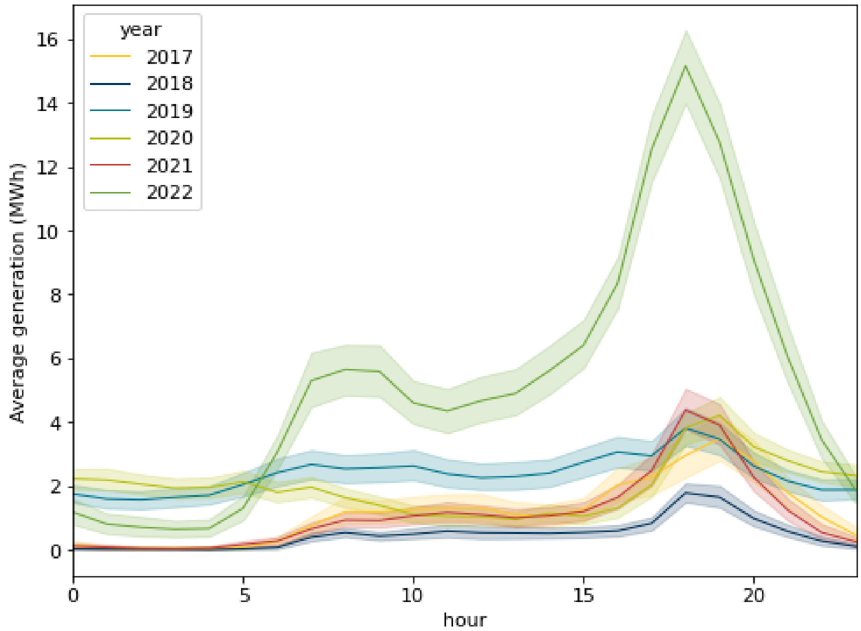
Operational characteristics of the Pinjar units

The analysis of dispatch cycle characteristics considered the observed dispatch of Pinjar units between 1 August 2017 and 31 July 2022. The following analysis was conducted to identify if the use of the whole 5-year observed dispatch data is appropriate for forecasting the future operation of the candidate machines.

The daily profile for the average output of Pinjar units is depicted in Figure 27. The chart shows a significant increase in the average output in 2022 when compared to previous years. This observation is consistent with Pinjar units being dispatched more frequently. After a decreasing trend since 2016, the output of the units has gradually increased during evening peak demand hours.

Figure 28 shows the daily profile of the number of starts across Pinjar units. The units start most frequently during the evening peak demand hours. In 2022, the number of starts during peak demand hours increased above that observed in the prior years.

Figure 27: Average generation per hour of day, Pinjar units

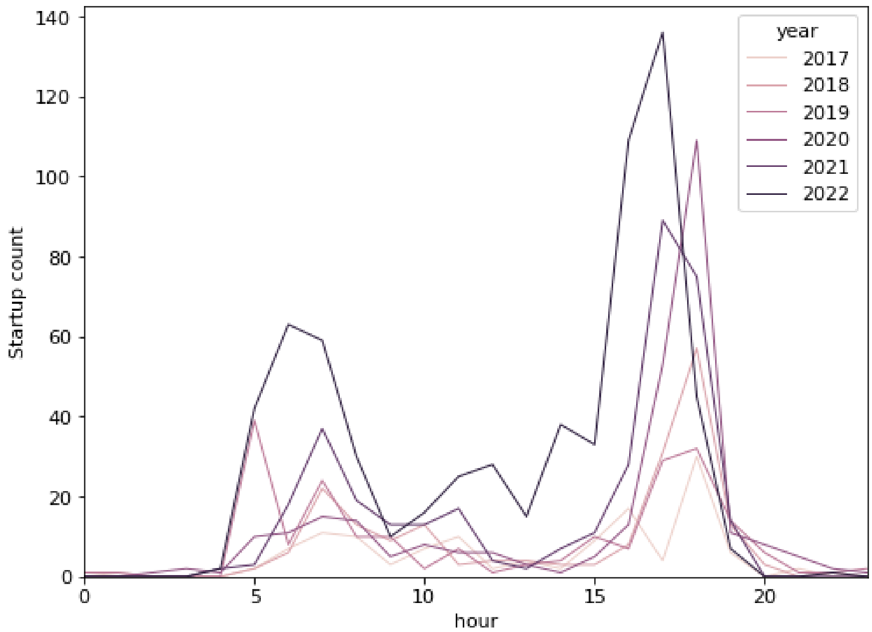


Source: ERA analysis using public SCADA data published by AEMO.

(a) *Note: The 2017 and 2022 samples do not cover complete years (Aug – Dec 2017; January to August 2022) as the analysis considers data over the past 5 years to August 2022.*

(b) *Note: shaded areas show the 95 per cent confidence interval for the average output.*

Figure 28: Number of starts hour of day, Pinjar units



Source: ERA's analysis using SCADA data published by AEMO

Note: The 2017 and 2022 samples do not cover complete years (Aug – Dec 2017; January to August 2022) as the analysis considers data over the past 5 years to August 2022.

The analysis of the Pinjar units' dispatch cycles since 2017 shows that:

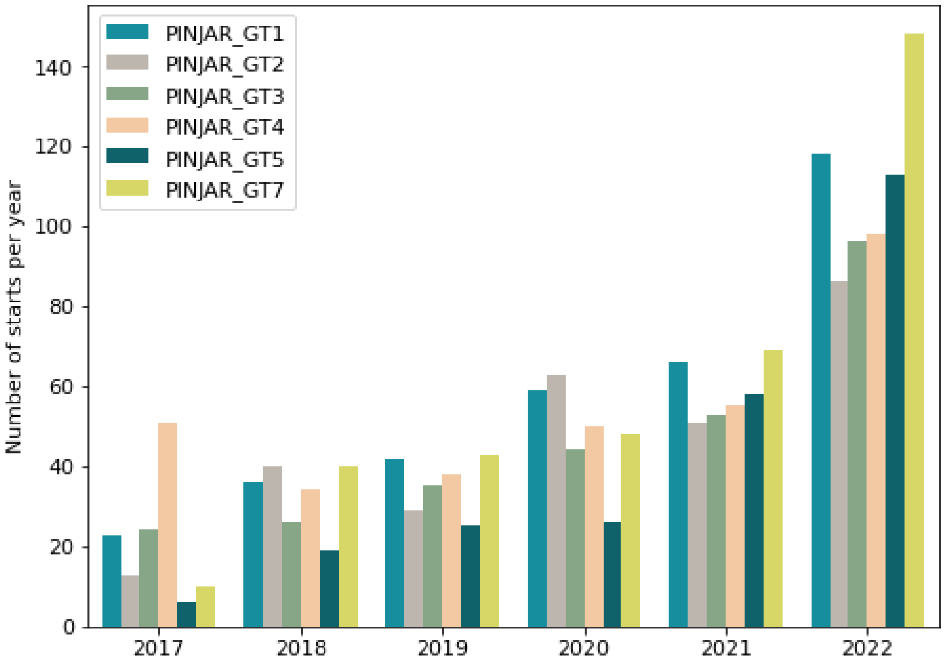
- The average duration of dispatch cycles is approximately 6.8 hours.
- The average generation per dispatch cycle is approximately 89 MWh.
- About 54 per cent of all dispatch cycles observed are dispatch cycles with a duration equal to or less than four hours – which in this report are referred to as short dispatch cycles. The observed dispatch contained dispatch cycles as short as 0.5 hours.

For clarity, the entire distribution of the annual number of dispatch cycles (including cycles lasting more than four hours) is used when determining the discounted VOM costs. This is because the maintenance intervals are driven by all starts of the machine, rather than short dispatch cycles only. As explained in the below section, an adjustment is made to the distribution of actual starts to account for the ratio of each actual start that counts as a factored start. This adjustment converted the sampled annual number of actual starts to a sampled factored start. The sampled factored starts were then used to determine the timing of future maintenance cash flows, as explained earlier.

Number of starts per year

Figure 29 shows the annual number of starts per year for each Pinjar unit. There has been a marked increase in the number of times each unit started in 2022 compared to previous years.

Figure 29: Annual number of starts, Pinjar units



Source: ERA's analysis using SCADA data published by AEMO.

Note: The 2017 and 2022 samples do not cover complete years (Aug – Dec 2017; January to August 2022) as the analysis considers data over the past 5 years to August 2022.

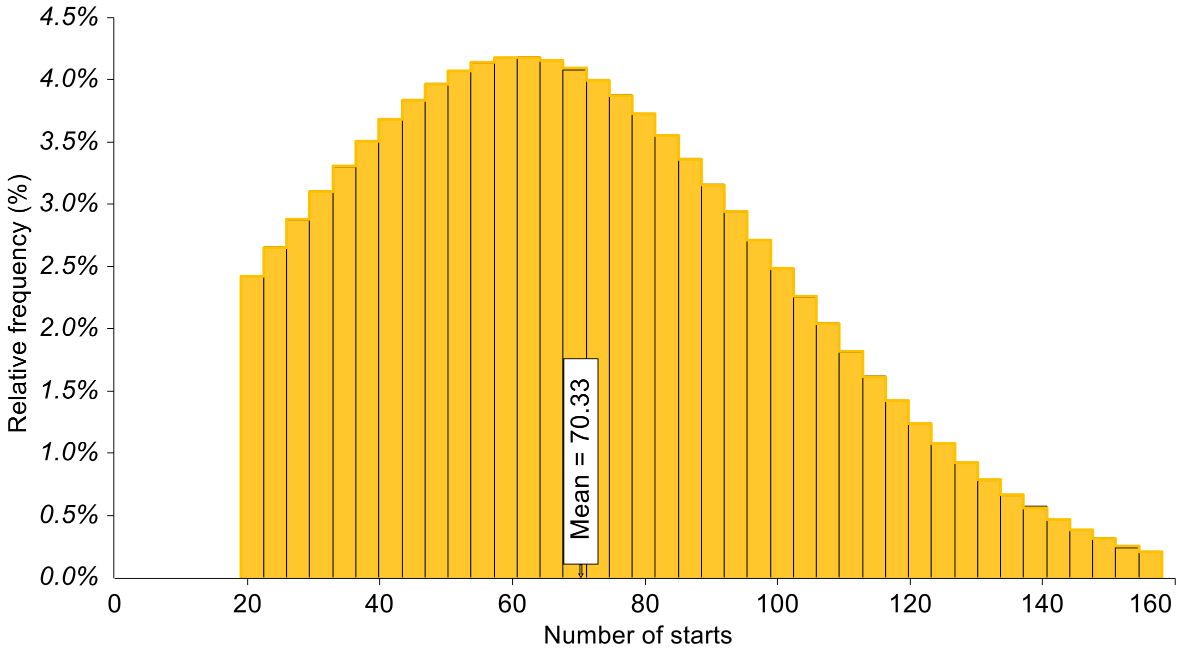
Over the study period, the Pinjar units:

- Started between 19 and 158 times a year individually.
- Started, on average, 61.2 times per year.

- the standard deviation of the number of starts per year was 38.7.

The ERA's modelling fitted a normal distribution to the number of starts per year, n_s, using the above information. Based on the range of observed annual number of starts, the lower and upper bound of the distribution was set to 19 and 158 starts per year, respectively. The resulting distribution is presented below (Figure 30).

Figure 30: Distribution of annual number of starts, Pinjar units



Note: ERA analysis of SCADA data published by AEMO.

Number of factored starts

The maintenance cycle described earlier is driven by the number of factored starts, n_{fs}. Each start of the machine contributes to the maintenance cost to a different level depending on operational conditions during that start. Each actual start of the machine is to be converted to number of factored starts using a ratio that considers the operational characteristics of actual starts. The original equipment manufacturer (GE) refers to the ratio of factored starts to actual starts as a maintenance factor.

For example, a start and trip from base load would count as eight factored starts (one cycle for start to base load, plus 8-1=7 cycles for trip from base load) for the maintenance type B. Therefore, an increase in the frequency of trips from base load operation shortens the maintenance intervals and increases variable maintenance costs related to maintenance type B. Secondly, part load starts up to 60 per cent of the maximum output of the unit only count as 0.5 factored starts for the maintenance type B. Part load operation of the unit therefore extends the maintenance interval for the type B maintenance. The factors driving the number of factored starts differ between maintenance types.

The ERA received information from Synergy on its calculation of factored starts for the combustion inspection maintenance (maintenance type A).

The ERA found that the original equipment manufacturer (GE) recommends a different calculation method for the number of factored starts for combustion inspection, hot gas path (type B maintenance) and major overhaul (type C maintenance).[87] For example, GE recommends that a low-load start (less than 60 per cent loading) contributes to 0.5 factored starts for planning maintenance type B and C. However, low load starts are not a contributing factor to determining the number of factored starts for maintenance type A.

Based on information received from Synergy and advice from GE, the ERA calculated the maintenance factors for maintenance types A, B and C, as below:

- Maintenance factor for type A maintenance $MF_A = 1.07$
- Maintenance factor for type B or C maintenance $MF_{B/C} = 0.680$

These factors are consistent with the factors used in the ERA's previous determination.

The simulation converts each sampled actual number of starts to the number of factored starts using the maintenance factors above:

$$n_{fs,i}(type\ A) = n_{s,i} \times MF_A$$

$$n_{fs,i}(type\ B\ or\ C) = n_{s,i} \times MF_{B/C}$$

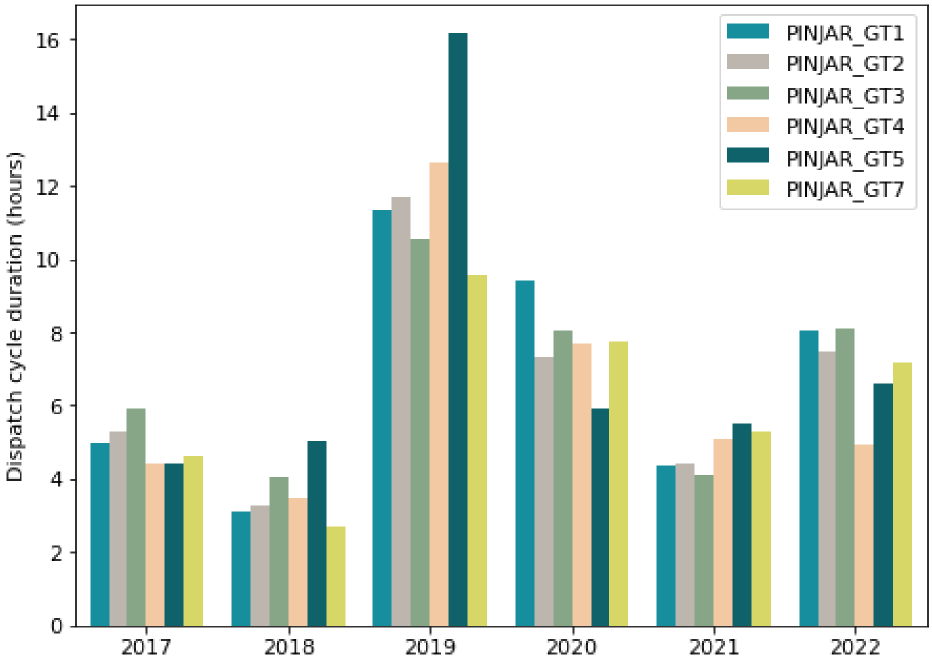
This provides for identifying the timing of future maintenance expenditures based on the number of factored starts per year in each simulation iteration i.

Duration of dispatch

The annual average dispatch cycle duration for the Pinjar units was between 2.7 and 15.0 hours, as shown in Figure 31. The average duration of all dispatch cycles across the review period was approximately 6.8 hours.

87 GE Power, 2021, *Heavy-Duty Gas Turbine Operating and Maintenance Considerations*, GER-3620P (01/21), (online), pp. 35, 36.

Figure 31: Average duration of all dispatch cycles, Pinjar units



Source: ERA's analysis using SCADA data published by AEMO

Note: The 2017 and 2022 samples do not cover complete years (Aug – Dec 2017; January to August 2022) as the analysis considers data over the past 5 years to August 2022.

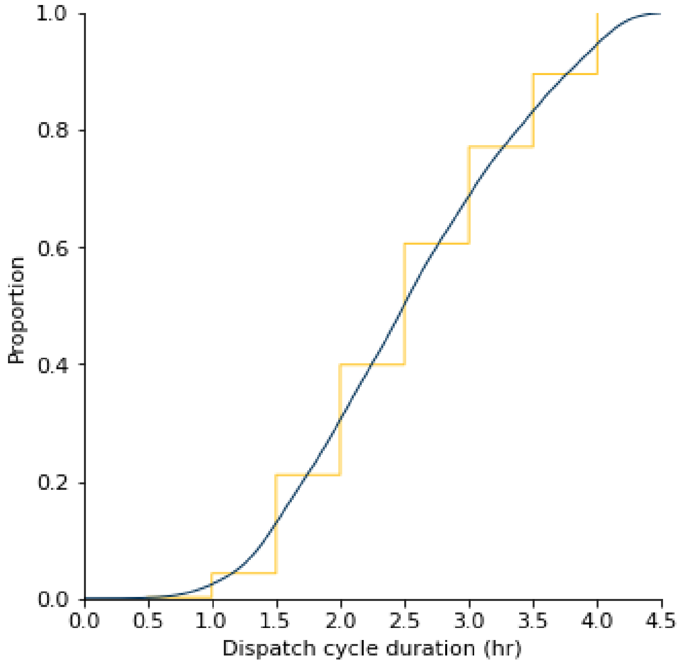
As noted earlier, the model samples from the distribution of short dispatch cycles between 0.5 and 4 hours to derive the VOM cost on a $/MWh basis. The model samples from the empirical distribution of short dispatch cycle duration, smoothed by a kernel-density estimate.[88] The empirical short dispatch cycle duration for Pinjar units is presented in Figure 32.

In the modelling of the energy price limits, the model includes the distribution of dispatch duration over short cycles, not just the average of the distribution, which was presented in Table 6.[89]

88 Kernel density estimation allows for estimating the probabilities associated with each dispatch cycle duration by smoothing the observed empirical distribution.

89 The average of the distribution as provided in Table 6 has been redacted for publishing as it is based on confidential data provided by Synergy.

Figure 32: Empirical cumulative distribution of dispatch cycle duration for short dispatch cycles, Pinjar units



Source: ERA's analysis using public SCADA data published by AEMO.

Note: the teal step curve shows the empirical cumulative distribution of dispatch cycle duration. The grey line shows the cumulative kernel-density estimate of the empirical distribution.

Maximum capacity

Consistent with the approach for the Parkeston units, this analysis assumes a constant maximum capacity for the Pinjar units. The model assumes the maximum capacity of the units to the maximum value observed over the past five years.

Relation between capacity factor and run time

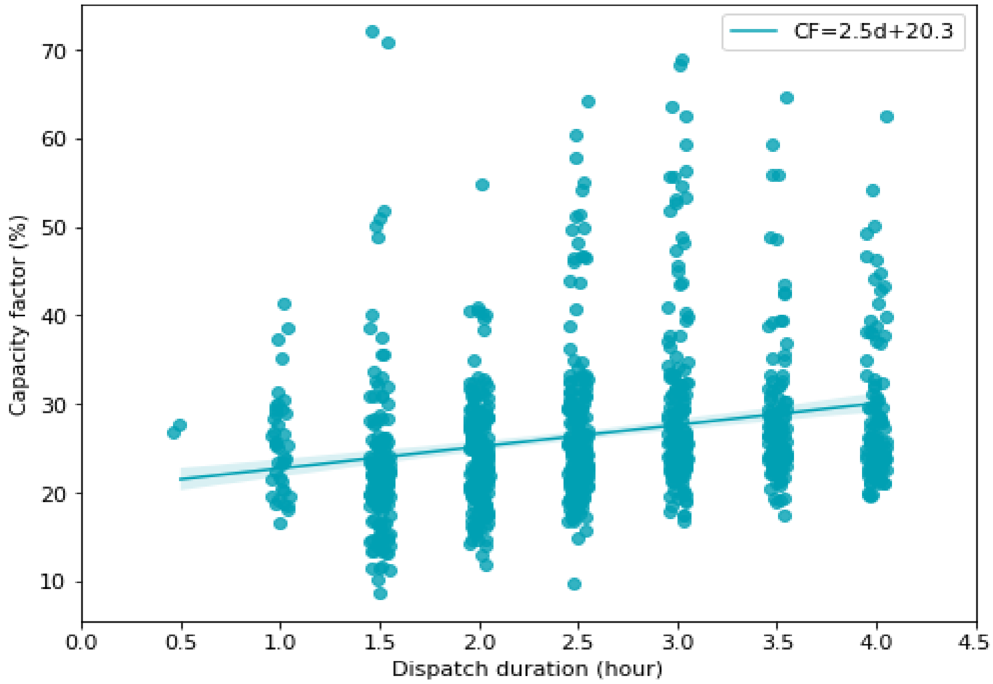
The model accounts for the relationship between the expected energy generated from different levels of dispatch cycle duration. This relationship was captured by analysing the historical short dispatch cycles for Pinjar. Figure 33 depicts the expected capacity factor over a dispatch cycle as a function of dispatch cycle duration, derived from the historical dispatch of the units.

The model uses the linear line fitted to the historical data to determine the expected capacity factor subject to the sampled run time. The model then randomly samples from the residuals of the fitted line, subject to run time, and adds the residual sampled to the expected capacity factor determined based on the regression line.

In the modelling of the energy price limits, the model includes the distribution of capacity factors over short cycles, not just the average of the distribution, which was presented in Table 6.[90]

[90] The average of the distribution as provided in Table 6 has been redacted for publishing as it is based on confidential data provided by Synergy.

Figure 33: Relationship between dispatch cycle duration and capacity factor, Pinjar units



Source: ERA's analysis using SCADA data published by AEMO.

Average generation over short dispatch cycles

As explained earlier, the analysis required an estimate of dispatch generation (MWh) over short dispatch cycles.

To derive a distribution of dispatch generation over short dispatch cycles, the ERA considered the product of the units' dispatch duration (hours), maximum capacity (MW) and capacity factor over short dispatch cycles. The product of these three variables yielded the amount (MWh) of electricity generated per start of the machine. The whole distribution, not just the average of the distribution, of each of the three variables was used to derive a distribution of electricity generated per start of the machine.

In the modelling of the energy price limits, the model includes the distribution of capacity factors over short cycles, not just the average of the distribution, which was presented in Table 6.[91]

Minimum capacity

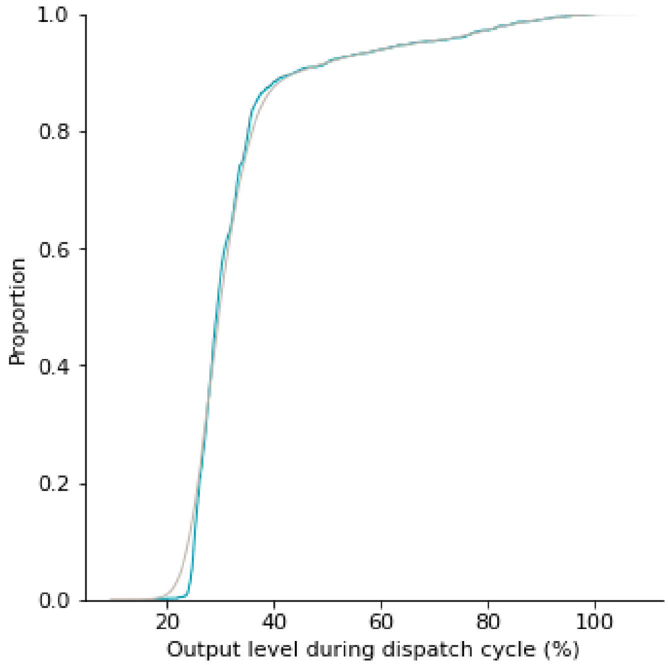
The analysis conducted to determine the distribution of minimum capacity of the Pinjar units was identical to the approach used for the Parkeston units, as explained in Appendix 2. The analysis considered the Pinjar units' observed output level during short dispatch cycles as a percentage of the maximum capacity of the units. Figure 34 shows the cumulative empirical distribution of the output level of Pinjar units observed over the review period.

[91] The average of the distribution as provided in Table 6 has been redacted for publishing as it is based on confidential data provided by Synergy.

As shown in Figure 34, the minimum capacity of the units was approximately 18 per cent of the maximum capacity. The probability of observing output levels below 18 per cent was negligible.

Based on the first 10 percentiles of the empirical distribution of output level for Pinjar, the minimum output level was modelled as a normal distribution, with a mean of 24.7 per cent of maximum capacity and a standard deviation of 1.39 per cent of maximum capacity. The lower and upper bounds of the distribution were set to 18.0 and 27.2 per cent of maximum capacity, respectively. The resulting distribution of the Pinjar units' minimum capacity is presented in Figure 35, with an average of 10.3 MW. This is largely comparable to the units' minimum stable generation level.

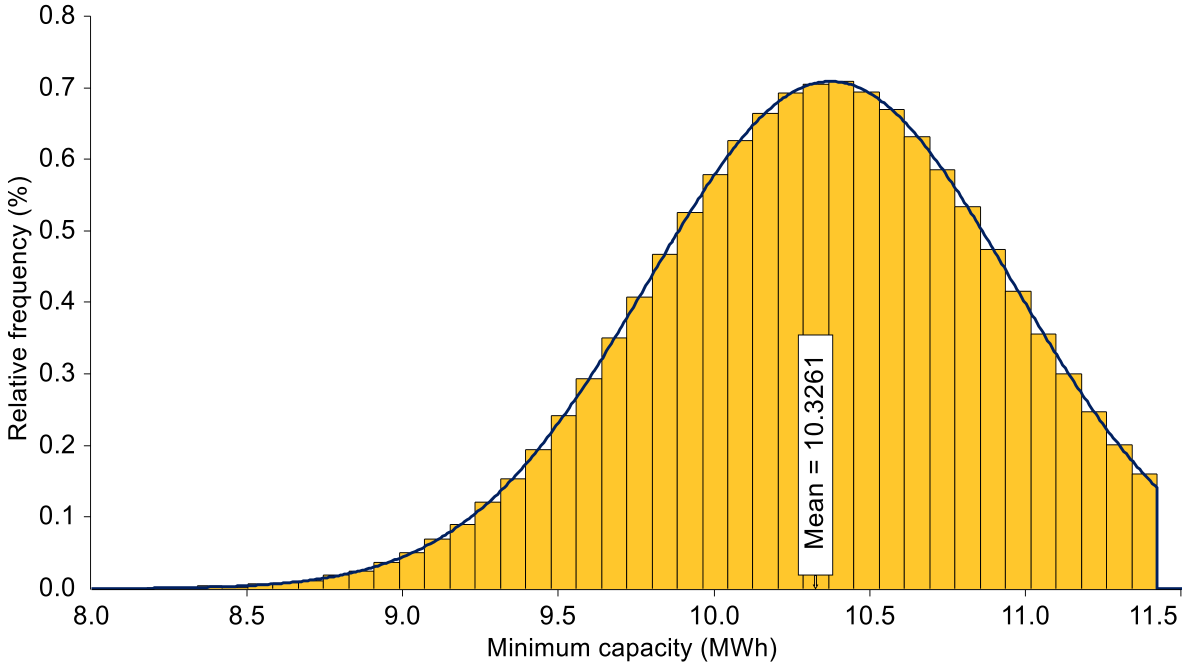
Figure 34: Empirical cumulative distribution of output level (capacity factor) reached during short dispatch cycles, Pinjar units



Source: ERA's analysis using SCADA data published by AEMO.

Note: The grey line shows the cumulative kernel-density estimate of the empirical distribution.

Figure 35: Distribution of minimum capacity, Pinjar units

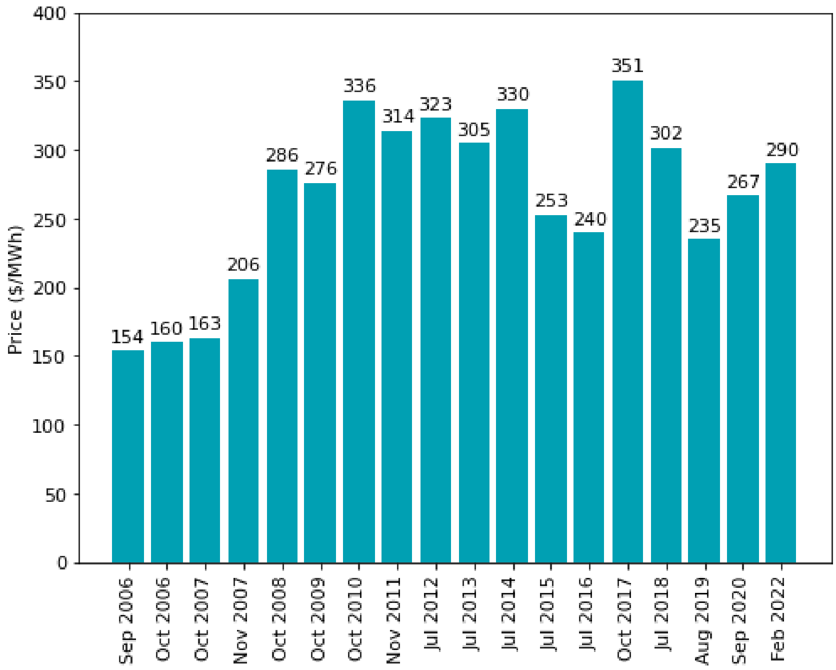


Source: ERA analysis based on confidential data provided by Synergy

Appendix 4 Historical price limits and market prices

This appendix presents historical energy price limits. Figure 36 and Figure 37 depict the historical number of trading intervals where the balancing market has settled at the maximum STEM price and alternative maximum STEM price since the market commenced.

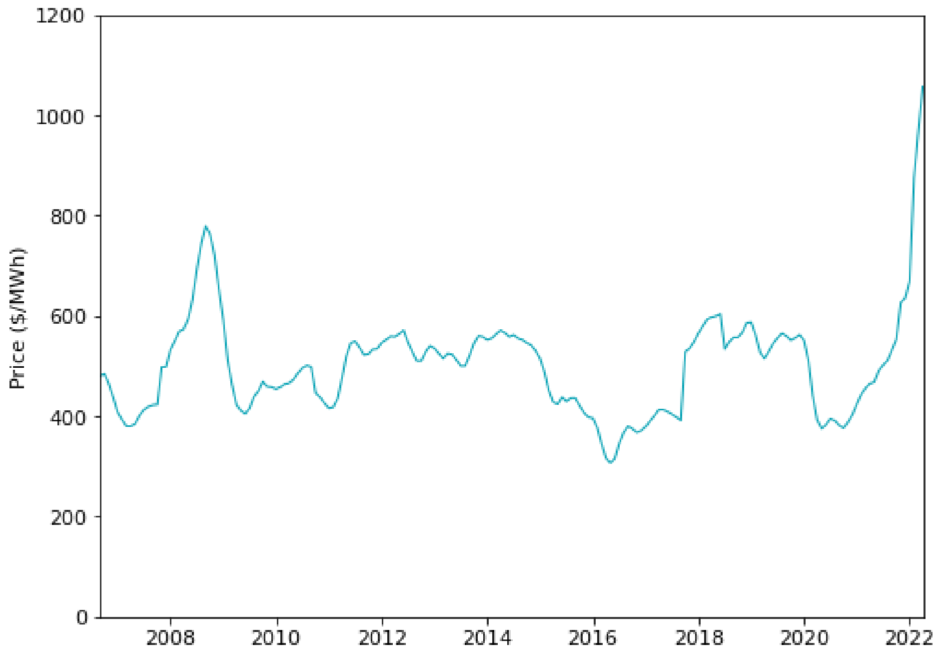
Figure 36: Historical maximum STEM price



Source: ERA's analysis using AEMO's published data.

Note: Dates show the month in which the price cap took effect. The February 2022 bar is not yet determined and proposed as part of this draft determination.

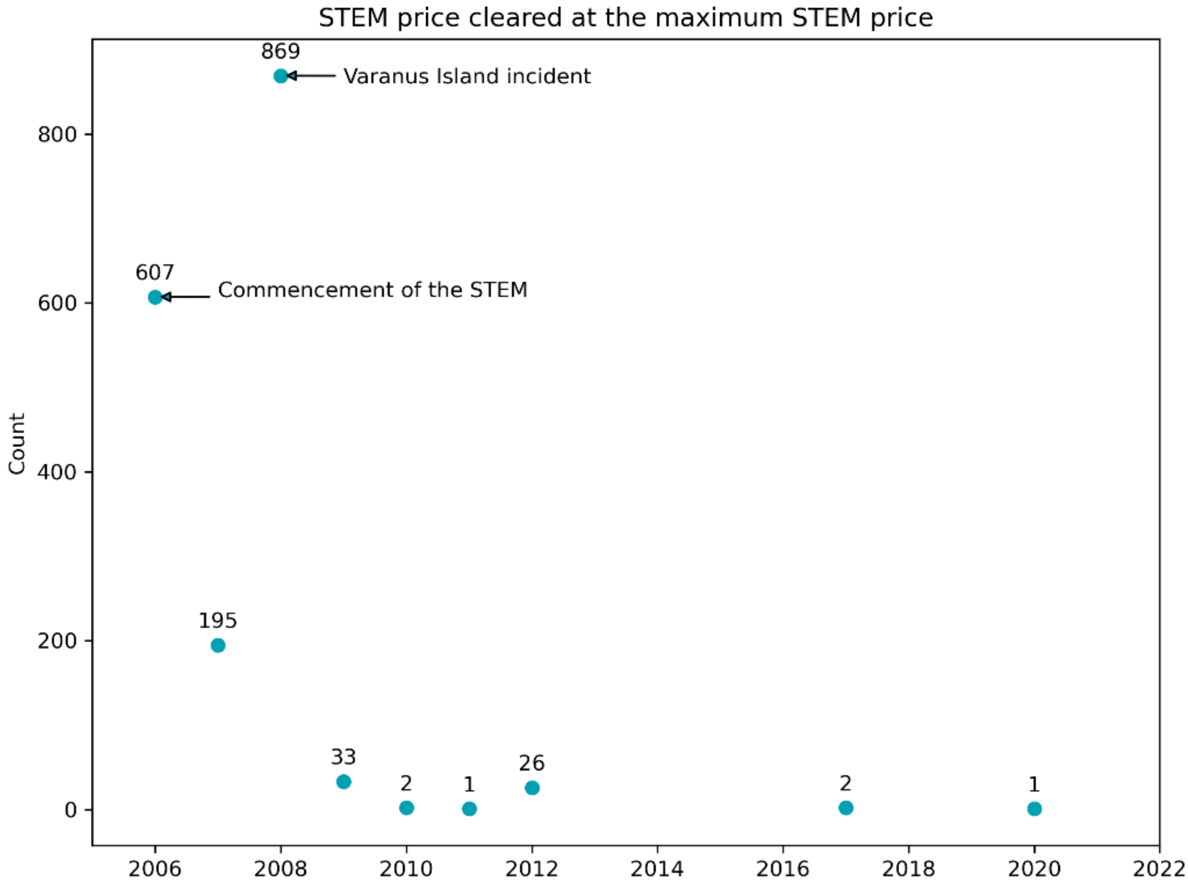
Figure 37: Historical alternative maximum STEM price



Source: ERA's analysis using AEMO's published data.

In recent years, the STEM has seldom cleared at the alternative maximum STEM price. Figure 38 shows the number of times the STEM has cleared at the maximum STEM price since the inception of the market in 2006. STEM prices cleared at the alternative maximum STEM price only 10 times during the early months after the commencement of the market.

Figure 38: Number of times the STEM cleared at the maximum STEM price



Source: ERA's analysis using AEMO's published data.

Note: the count shown for 2022 is based on information available as of 1 November 2022.

Appendix 5 List of Tables

Appendix 6 List of Figures