Energy price limits review 2021

Draft report

24 November 2021

Economic Regulation Authority
WESTERN AUSTRALIA

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Friday 31 December 2021.

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:

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Post: Level 4, Albert Facey House, 469 Wellington Street, Perth WA 6000

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.

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Executive summary

In the Wholesale Electricity Market (WEM), participants offer energy and ancillary services to meet real-time demand for energy. Offers into the energy markets (short term energy market and balancing market) are subject to a set of price limits to mitigate the exercise of market power.

These price limits are set based on the short run marginal cost of the highest cost generating works in the South West Interconnected System (SWIS).

This draft report outlines the Economic Regulation Authority's estimate of the revised values for those price limits.

The ERA is seeking feedback from stakeholders on the estimated price limits. After considering feedback from stakeholders, the ERA will publish a final determination and the revised price limits will take effect on a date specified by the Australian Energy Market Operator (AEMO).

The WEM Rules specify two maximum price limits:

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

The WEM Rules require that these 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. 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 unit.

The ERA has based its draft determination of the energy price limits on the highest supply cost of the highest cost generator in the SWIS, under 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 responsibility for the annual review and determination of the price limits was transferred to the ERA on 1 July 2021. AEMO was previously responsible for proposing any revised values for the price limits to the ERA for approval.

Proposed price limits

The ERA proposes the maximum STEM price of $290/MWh. This is higher than the current maximum STEM price of $267/MWh, which took effect on 1 September 2020.

The ERA also proposes the following indexation formula for determining the alternative maximum STEM price:

$$\begin{aligned} &\mathit{alternative\ maximum\ STEM\ price} \\ &\qquad = 33.763 + 25.453 \times \mathit{net\ ex\text{–}terminal\ distillate\ price}\ (\$/GJ) \end{aligned}$$

At the current distillate price of $24.3/GJ (net of excise and goods and services tax), the ERA's revised indexation formula yields a higher value for the alternative maximum STEM price of $652/MWh when compared to $607/MWh determined last year.

The increase in the estimated price limits follows a change in how the ERA has calculated the generators' mean heat rates to better reflect the requirements of the WEM Rules. The ERA has estimated heat rates at the high-cost operating conditions typically expected at low output levels around the limit of minimum stable generation. Previous energy price limit reviews relied on estimating heat rates at higher levels of output. Changing to heat rate estimates around minimum stable generation and the ERA's assumptions on forecast gas prices has identified the gas turbines at Parkeston Power Station as the highest cost 40 MW open cycle gas generators in the SWIS and so these units have set the price limits this year. Previous reviews considered the smaller industrial gas turbines at Pinjar Power Station as the highest cost generators.

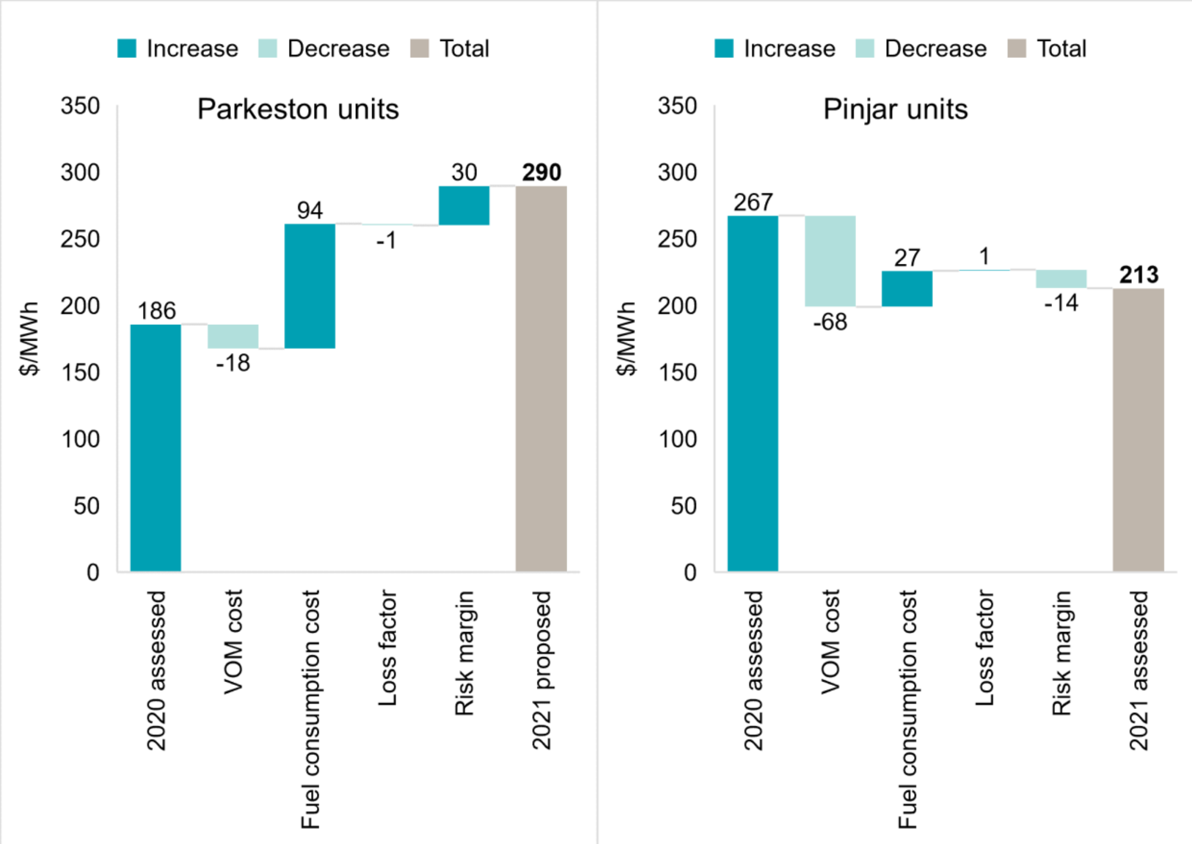
There are other differences in the values used for estimating the price limits when compared to previous years. Given its functions and powers under the WEM Rules and the *Economic Regulation Authority Act 2003,* the ERA can obtain information from market participants that AEMO may not have had access to in previous years.

The ERA received information on the Pinjar units' variable operational and maintenance (VOM) costs from the asset operator, Synergy, which were significantly lower than VOM costs estimated by AEMO in previous reviews. Consequently, the VOM cost component of the price limits calculation has declined significantly compared to last year, resulting in the Pinjar units no longer being determined as the highest cost generator in the SWIS.

This draft report describes how the ERA has arrived at the proposed revised values for the maximum STEM price and alternative maximum STEM price. It also includes details of how the ERA determined the appropriate values to apply for the factors in determining the price limits, as described in clauses 6.20.7(b)(i) to 6.20.7(b)(v) of the WEM Rules.

Figure 1 shows the effect of changes in the underlying variables of the price limits calculations for both the Pinjar and Parkeston units.

Figure 1. Change in the components of the energy price limits calculation from the previous review, Parkeston and Pinjar units



Note: The 2020 assessed figure for the Parkeston units ($186/MWh) is based on average variable cost (including a risk margin) of the Parkeston units in the previous year's review. The 2020 assessed figure for the Pinjar units ($267/MWh) is based on the maximum STEM price determined in the previous year's review. The Pinjar units, not the Parkeston units, set the price cap in the previous year's review. Values may not add up due to rounding.

The reduction in the variable operating costs for the Parkeston units (left hand figure) above results from a change in maintenance expenditure drivers. In this draft determination, maintenance expenditure has been calculated based on the hours of operation, consistent with the asset operator's approach and advice from the equipment manufacturer. The increase in the fuel consumption cost parameter for the Parkeston units is a feature of the ERA's approach to determining the generator's heat rate at minimum capacity.

The main change in the variable operating costs from the Pinjar units is from Synergy providing information on maintenance costs. Previously, costs were higher as AEMO's consultants were reliant on estimates and publicly available information.

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.[1] These price limits are set based on the short run marginal cost of the highest cost generating works in the SWIS.[2]

The energy price limits comprise:

- The maximum STEM price: this applies to offers from all facilities except those using distillate as the fuel source.
- The alternative maximum STEM price: this applies to generators that use distillate as a fuel source, which typically have a higher cost of supply than generators that use fuel sources other than distillate.
- The minimum STEM price: this is currently set at negative $1,000/MWh and is not part of this review.[3]

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 last reviewed by AEMO and approved by the ERA in 2020. The maximum STEM price is currently set at $267/MWh. The alternative maximum STEM price is indexed to the distillate price and is updated by AEMO monthly. Based on the distillate price as of October 2021, the alternative maximum STEM price is $502/MWh.[4]

Since 2017, the maximum STEM price has varied between $235/MWh and $351/MWh, resulting from changes in input costs and calculation method in practice. However, over the same period, the STEM and balancing market have seldom settled at the price cap or above $200/MWh. Historical price limits and market clearing prices are presented in Appendix 5. Figure 2 shows the number of times the balancing market cleared at the maximum STEM price since the inception of the market in 2012.

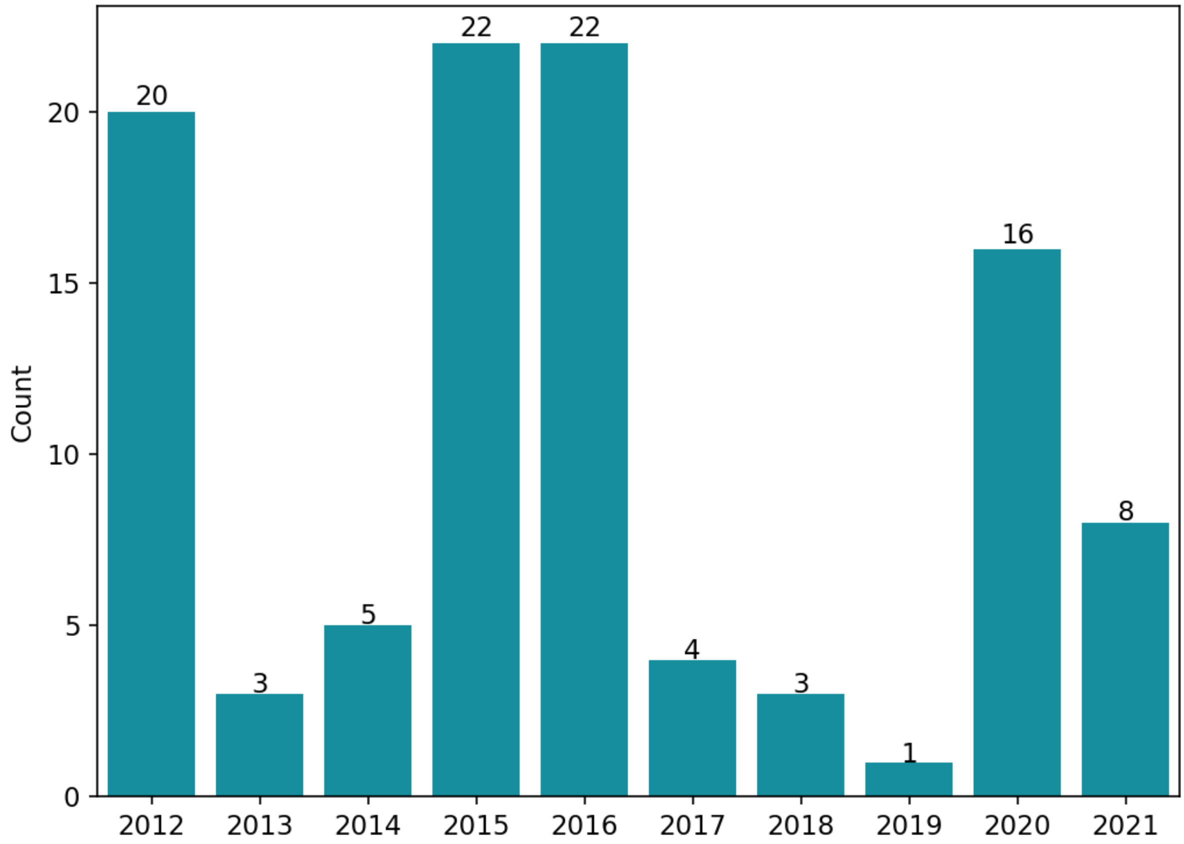
1 Other market power mitigation mechanisms in the WEM include mandatory provision of capacity in the energy markets and ex post market monitoring.

2 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 dollar per megawatt-hour ($/MWh).

3 From 1 February 2021, 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 review and concluded that the current minimum STEM price of negative $1,000/MWh is appropriate. ERA, 2021, *Minimum STEM price review 2021 – Final determination*, (online).

4 AEMO, 2021, Current prices and limits, (online).

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



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

Note: the count shown for 2021 is based on information available as of October 2021.

1.1 The ERA's obligations under the WEM Rules

Prior to 1 July 2021, AEMO was responsible for determining the energy price limits according to the method and guiding principles outlined in the WEM Rules. The ERA was responsible for approving the revised values proposed by AEMO after considering whether AEMO had followed the method and guiding principles outlined in the WEM Rules, and whether AEMO had carried out an adequate public consultation process.

On 22 January 2021, the Minister of Energy transferred the function of annually reviewing and determining the energy price limits from AEMO to the ERA from 1 July 2021:

> 6.20.6. The Economic Regulation Authority must annually review the appropriateness of the value of the Maximum STEM Price and Alternative Maximum STEM Price. [5]

On 15 February 2021, AEMO advised the ERA Secretariat that it would not commence the annual review of the energy price limits in 2021, given the ERA would be responsible for carrying out this function from 1 July 2021. AEMO noted that previous annual reviews of the energy price limits were typically completed by the end of the financial year. However, the WEM Rules do not specify an exact timeframe for when the annual review must occur and

5 Wholesale Electricity Market Rules, 1 October 2021, clause 6.20.6, (online).

there is no express requirement to start or complete the review by a specific date. The ERA Secretariat agreed with AEMO's assessment.

From 1 July 2021, 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 SWIS:

> 6.20.7. In conducting the review required by clause 6.20.6 the Economic Regulation Authority:
>
> (a) may propose revised values for the following:
>
> i. the Maximum STEM Price, where this is to be based on the Economic Regulation Authority's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas and is to be calculated using the formula in paragraph (b); and
>
> ii. the Alternative Maximum STEM Price, where this is to be based on the Economic Regulation Authority's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by distillate and is to be calculated using the formula in paragraph (b).
>
> (b) must calculate the Maximum STEM Price or Alternative Maximum STEM Price using the following formula:
>
> $$(1 + Risk\ Margin) \times \frac{Variable\ O\&M\ Cost + (Heat\ Rate \times Fuel\ Cost)}{Loss\ Factor}$$
>
> where:
>
> i. $Risk\ Margin$ 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;
>
> ii. $Variable\ O\&M\ Cost$ 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;
>
> iii. $Heat\ Rate$ is the mean heat rate at minimum capacity for a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;
>
> iv. $Fuel\ Cost$ is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station, expressed in $/GJ; and
>
> v. $Loss\ Factor$ is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the Reference Node.
>
> Where the Economic Regulation Authority must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price. [6]

The WEM Rules require the ERA to publish a draft report for consultation, describing how it determined any revised values of the maximum energy price limits.

> 6.20.9. In conducting the review required by clause 6.20.6 the Economic Regulation Authority must prepare a draft report describing how it has arrived at a proposed revised value of one or both of the Maximum STEM Price and

[6] Ibid, clause 6.20.7.

Alternative Maximum STEM Price. The draft report must also include details of how the Economic Regulation Authority determined the appropriate values to apply for the factors described in clauses 6.20.7(b)(i) to 6.20.7(b)(v). The Economic Regulation Authority must publish the draft report on the WEM Website and advertise the report in newspapers widely published in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users, within six weeks of the date of publication.[7]

After considering the submissions, the ERA must propose final revised values for the maximum energy price limits:

6.20.10. The Economic Regulation Authority must consider in-time submissions on the draft report described in clause 6.20.9, and any in-time submissions received under clause 6.20.9A, and may consider any late submissions, and after considering the submissions must propose a final revised value for one or both of the Maximum STEM Price and Alternative Maximum STEM Price.[8]

The revised values proposed by the ERA will take effect on a date specified by AEMO:

6.20.11 A proposed revised value for the Maximum STEM Price and the Alternative Maximum STEM Price replaces the previous value after AEMO has posted a notice on the WEM Website of the new value of the applicable Energy Price Limit, with effect from the time specified in AEMO's notice.[9]

Relevant excerpts of the WEM Rules are provided in Appendix 1.

1.1.1 Information gathering

The determination of the energy price limits requires data for estimating generators' fuel costs, heat rate and VOM costs.

Previous reviews of the energy price limits were based on public data and any information provided voluntarily by market participants. AEMO did not have any specific authority to compel market participants to provide information for the purpose of reviewing the energy price limits. In contrast, the ERA's functions under the legislation enable the ERA to access and gather data from multiple sources. Consequently, the ERA has a richer source of information available to it to calculate energy price limits.[10] This improved data access has driven some of the changes in the draft energy prices limits for 2021.

The ERA requested and received data from asset operators on their respective generating units, which includes:

- historical data, such as dispatch profiles, heat rates, and fuel and non-fuel costs
- market participants' estimate of a generator's VOM costs
- any forecast or assumptions of future fuel and non-fuel costs.

[7] Ibid, clause 6.20.9.

[8] Ibid, clause 6.20.10.

[9] Ibid, clause 6.20.11.

[10] Section 51 of the *ERA Act 2003* (WA) (online) stipulates that if the ERA has reason to believe that a person has any information that may assist the ERA in the performance of its functions, the ERA may require the person to give the ERA the information. Clause 2.16.6 of the *Wholesale Electricity Market Rules (1 October 2021)* (online) allows the ERA to collect additional information from market participants if the ERA considers it necessary or desirable for the performance of its functions.

For this review, the ERA has also gathered information from other sources:

- the original equipment manufacturer of the turbines
- AEMO and its consultants that carried out previous reviews of the energy price limits
- public data from the WEM and other jurisdictions.

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 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. Goldfields Power and Synergy requested that the data provided to the ERA be redacted throughout this document. The ERA would have preferred to publish the information in the interest of transparency and openness in the market and asked Goldfields Power and Synergy if any of the information could be published. Both participants indicated they would prefer the confidential information remain redacted. As a result, the information that was received from the participants has been redacted in this document, but the ERA's estimates of inputs to the energy price limits calculation based on participants' data are 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 clause 6.20.7(b) of 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.[11] This protects market customers from high prices that could result from generators exercising market power in the energy markets; and
- 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.

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 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 approach is consistent with the practice to determine risk margins in previous reviews of the price limits.

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.

[11] 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 October 2021, clause 6.26.3, (online).

Firstly, setting the price limits based on the higher of possible values allows generators to recover their costs. Setting the price limits too high can reduce the effectiveness of the price limits in limiting the exercise of market power. However, the WEM Rules contain other market power mitigation mechanisms to mitigate this risk.[12] 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 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.[13] If the ERA cannot infer a reasonable range for an input that is highly uncertain, there is a risk that the calculated risk margin will not sufficiently account for the high level of uncertainty, and consequently the price limit would not be high enough to sufficiently compensate high-cost generators under high-cost supply conditions.

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 (Parkeston units 1 to 3) as machines that fulfil the criteria of the WEM Rules. Since the energy price limits were first determined, the Pinjar units have consistently had the highest cost of supply for short dispatch periods, followed by the Parkeston units.

The Pinjar units are owned and operated by Synergy and are used to provide peaking power in the SWIS. The Parkeston units are owned and operated by Goldfields Power, which is jointly owned by Newmont AP Power and TransAlta Corporation. Both Pinjar and Parkeston gas turbine units are manufactured by General Electric (GE).[14]

[12] 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. As part of the Energy Transformation Strategy, Energy Policy WA has proposed a range of mechanisms to mitigate the exercise of market power. See EPWA, 2021, *Improvements to Market Power Mitigation Mechanism – Information Paper*, (online).

[13] The formula in the WEM Rules requires the ERA to estimate a generator's VOM cost, fuel cost and heat rate at minimum capacity. The rules do not define minimum capacity and in previous years AEMO's consultants have interpreted this as minimum observed capacity rather than as the ERA has interpreted the term as at or around minimum stable generation. 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.

[14] In GE nomenclature, the Pinjar units are Frame 6B heavy duty gas turbines and the Parkeston units are LM6000A aeroderivative gas turbines.

Since the last review, 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.[15]

The ERA's analysis in this review concludes that the Parkeston units are currently the highest cost generators in the SWIS and will set the energy price limits. Recent reviews of the price limits considered the Pinjar units as the highest cost generators in the SWIS. This change is driven by the following factors:

- The improved method for estimating the average heat rate at minimum capacity better reflects the requirements of the WEM Rules. The estimate of average heat rate at minimum capacity for Parkeston is substantially higher than that used in previous reviews of the price limits. This is explained in detail in section 2.4.
- Information received from Synergy suggest the VOM costs for the Pinjar units are substantially lower than those estimated by AEMO's consultant in previous reviews of the price limits. As a result, the Pinjar units' VOM cost estimate is lower than the estimate in previous reviews. This is explained in detail in Appendix 2.

2.2 Variable operating and maintenance cost

The WEM Rules do not specify a method for determining VOM costs, which include start-up costs.

The VOM cost component includes any costs incurred in operating a generator (other than fuel cost) and conducting periodic maintenance work 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. This is consistent with the approach adopted in previous reviews of the price limits.

In recent reviews of the price limits, the mean VOM cost estimated for the Pinjar units, and thus included in price limits, varied between $70/MWh to $130/MWh.[16] This accounted for 28 per cent to 44 per cent of the determined price limits.

Variable maintenance expenditures are the main component of the VOM costs. Variations in the estimate of VOM costs across years were related to changes in the:

- Estimate of variable maintenance expenditures for the Pinjar units.[17]
- Method used to spread those expenditures over each start of the units, and then subsequently over each unit of energy generated.

[15] 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.

[16] In the 2020 review, the Pinjar units' mean VOM cost was estimated as $110/MWh. Historical annual reviews of the energy price limits are available on the ERA's website, (online).

[17] In recent years, the Pinjar units have been considered the highest cost generating works and its supply cost has underpinned the determination of price limits. The ERA's analysis this year concluded that the Parkeston units are the highest cost generating works in the SWIS.

In recent reviews of the price limits, the estimate of mean VOM costs for the Parkeston units has varied significantly between reviews.[18] The Parkeston units did not previously set the price limits despite the substantial increase in its estimate of VOM costs. This was because, historically, the increase in VOM costs did not offset the lower cost related to fuel for Parkeston when compared to Pinjar.

To estimate VOM costs, the ERA considered several sources of information from the asset owners, the equipment manufacturer GE and previous reviews of the price limits. The ERA received both asset owners' estimates of VOM costs for the Pinjar and Parkeston units.

The ERA has estimated the average VOM cost for the Parkeston units as $30.1/MWh, which was based on information provided by Goldfields Power and generally comparable to the original equipment manufacturer's estimates for similar gas turbines.[19,20]

The estimated VOM cost for the Parkeston units is substantially lower than the estimate that AEMO's consultants calculated over the past two years. This is because:

- The method used last year relied on public sources of information on variable maintenance expenditures.
- The ERA has revised the method used previously by AEMO to estimate VOM costs for the Parkeston units to ensure it is consistent with the approach taken by the asset owner and the equipment manufacturer.[21]

Section 2.2.1 explains the process of estimating the Parkeston units' VOM costs. A similar explanation for the Pinjar units' VOM costs is provided in Appendix 2.

2.2.1 Estimation of VOM costs for Parkeston

The ERA received Goldfields Power's estimate of its VOM costs for the Parkeston units. This comprised of the following costs:

- Start-up costs estimated as [redacted] per start, which includes start-up fuel consumption.

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[18] AEMO's consultants estimated the mean VOM cost for the Parkeston units as $8.49/MWh, $89.70/MWh and $50.55/MWh in 2018, 2019 and 2020 respectively. See:
Jacobs, 2018, *Energy Price Limits for the Wholesale Electricity Market in Western Australia – Final Report*, p. 65, (online).
Marsden Jacobs, 2019, *2019-20 Energy Price Limits Review – Final Report (Public) – A report for the Australian Energy Market Operator*, p. 39, (online).
Marsden Jacobs, 2020, *2020-21 Energy Price Limits Review – Final Report (Public) – A report for the Australian Energy Market Operator*, p. 47, (online).

[19] This estimate for average VOM cost includes the cost related to start-up fuel, which on average accounts for [redacted]. In comparison, previous reviews of the price limits included the start-up fuel cost in the fuel cost component of the price cap.

[20] The ERA received advice from GE that a major overhaul for a LM60000PA turbine is due after [redacted] hours of operation and costs approximately [redacted], resulting in an approximate cost per operating hour of [redacted] which is comparable to the cost of [redacted] per operating hour provided by Goldfields Power. For comparison, in 2020 WSP estimated VOM costs for a similar LM6000 gas turbine in New Zealand (Huntley unit 6) at approximately NZD$10/MWh (as of October 2021, one Australian dollar is 1.06 New Zealand dollar). This estimate is also reliant on escalation of historic available data. Refer to WSP, 2020 thermal generation stack update report, prepared for the Ministry of Business, Innovation and Employment, p. 14, (online).

[21] Information received from GE shows that maintenance expenditures for the Parkeston units are driven by hours of operation. Previous reviews of the price limits until 2018 also considered that maintenance works for the Parkeston units are driven by hours of operation. See: Jacobs, 2018, *Energy price limits for the Wholesale Electricity Market in Western Australia*, p. 62, (online).

- Cost per operating hour of [redacted], which covers long-term major variable maintenance and overhaul costs.
- Other VOM costs of [redacted] per MWh, which covers incidentals such as oil and water.

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.[22] 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 energy generated reflects very high-cost operating conditions of the units. This conversion approach is consistent with those used in the previous reviews of the price limits and is explained in section 2.2.2.

2.2.2 Conversion of variable operating and maintenance costs to 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.

Consistent with the approach in previous reviews, a dispatch cycle is used to capture such variations in the form of a dispatch cycle duration and output distributions.[23] This is explained in detail in Appendix 4.

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

- run time for a short dispatch cycle (between 0.5 and 6 hours), expressed in hours
- dispatch cycle capacity factor as a function of run time, expressed as a percentage
- maximum capacity, expressed in MW.

The product of these three variables yields the MWh of electricity generated per start of the machine. The estimation of parameters used for the conversion of costs are explained in detail in Appendix 4.

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

- The start-up cost (as indicated in the previous section) is divided by the product of sampled run time, capacity factor, and maximum capacity to estimate start-up costs on a per MWh basis.
- The cost per operating hour is divided by the product of capacity factor (subject to sampled dispatch cycle duration) and maximum capacity to express them on a per MWh basis.

[22] 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.

[23] 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 and dispatch cycle duration.

Table 1. Estimate of VOM costs for Parkeston units

Item	Unit	Value	Notes
Cost per operating hour	$/hour	[redacted]	Contracted fee to cover long-term major maintenance and overhaul costs.
Start-up cost	$/start	[redacted]	Includes start-up fuel consumption.
Incidentals	$/MWh	[redacted]	Covers incidentals such as oil and water.
Average duration of dispatch per start (short dispatch)	Hours	3.2	Duration of short dispatch is sampled from a distribution. See details in Appendix 4.
Mean energy generated per start (short dispatch)	MWh/start	67.4	Energy generated over a short dispatch is sampled from a distribution. See details in Appendix 4.
Average capacity factor as a function of runtime (short dispatch)	%	49.7	Capacity factor is estimated based on sampled short dispatch duration. See details in Appendix 4.
Mean VOM cost	**$/MWh**	**30.1**	**Average of the distribution of VOM costs.**

Source: ERA analysis of Parkeston data as provided by Goldfields Power.

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 forecasts of gas price based on information available on maximum price cleared monthly in the gasTrading platform – a trading platform through which sellers and buyers generally trade gas on a month-ahead basis. In the 2020 review, AEMO used the weighted average gas price reported by the Department of Mines, Industry Regulation and Safety (DMIRS), following feedback from stakeholders that the higher level of prices observed through DMIRS data better reflected the market price of gas.[24, 25]

To estimate the fuel cost component of the energy price limits calculation, the ERA considered both Goldfields Power's and Synergy's expected cost of sourcing gas over the next 12 months, public sources of data and a forecast of gas spot prices as developed by the ERA's independent consultant, Jacobs (Appendix 8). Each source of information is considered in determining the forecast gas price used in determining energy price limits, as discussed in section 2.3.1.

[24] Marsden Jacobs, 2020, *2020-21 Energy Price Limits Review – Final Report (Public) – A report for the Australian Energy Market Operator*, p. 37, (online).

[25] DMIRS, 2020, *Latest statistics release – 2020 Major commodities resources data*, (online).

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 minimum stable level of generation.

To estimate the fuel supply cost of the Parkeston units, the ERA used Jacobs' forecast gas price of $5.04/GJ (undelivered) over the next 12 months and a gas transportation cost of $4.564/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.[26,27] Overall, this yields a delivered gas cost of $9.60/GJ, before 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 Jacobs $5.04/GJ forecast gas price as the preferred indicator of the cost of acquiring gas in the market over the forward period. Jacobs' forecast also provided a distribution of gas costs, which enabled the ERA to consider 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 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. ERA assessed available capacity and supply and demand conditions on the GGP in selecting the gas transportation cost of $4.564/GJ in its estimate of energy price limits. This is detailed in section 2.3.2.

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 (typically 5 years to 20 years) forward contracts to limit their exposure to the risk of variable fuel prices. Others might source all or part of their gas through short-term (between a month to a day ahead) trading platforms. Apart from the gasTrading platform, prices and trade quantities for other trading arrangements or bilateral contracts are not published.[28]

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 candidate machines over the planning horizon:[29]

[26] 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.

[27] The ERA sets reference tariffs for the covered capacity on the GGP. Parties negotiate transportation tariffs for individual contracts. Jacobs forecasts transmission cost based on the covered tariffs on the GGP with an average of $1.388/GJ.

[28] 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.

[29] 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.

- Forecast of natural gas price produced by the ERA's independent consultant, Jacobs.[30] This forecast relies on observed prices in the gasTrading platform to project prices over the coming year.[31] Jacobs also considered the volume weighted average price of gas as published by DMIRS but recommended the use of maximum monthly spot prices from the gasTrading platform for the ERA's review.

- Information received from the asset owners, Synergy and Goldfields Power, on their contract price for gas and possible sourcing opportunities and transportation charges.

Each of the above 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 Jacobs' forecast is based on 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 estimating the fuel cost component of the price limits.

The ERA engaged Jacobs to prepare a forecast of gas prices as a possible input to the fuel cost parameter of the energy price limits determination. Jacobs considered the general conditions in the gas supply and demand in Western Australia and used a time series analysis to forecast gas prices over the coming year. The general approach for the analysis this year is similar to that conducted in previous reviews of the price limits. Jacobs considered two sources of data:

- maximum monthly spot price from the gasTading platform

- average quarterly WA natural gas price supplied by DMIRS.

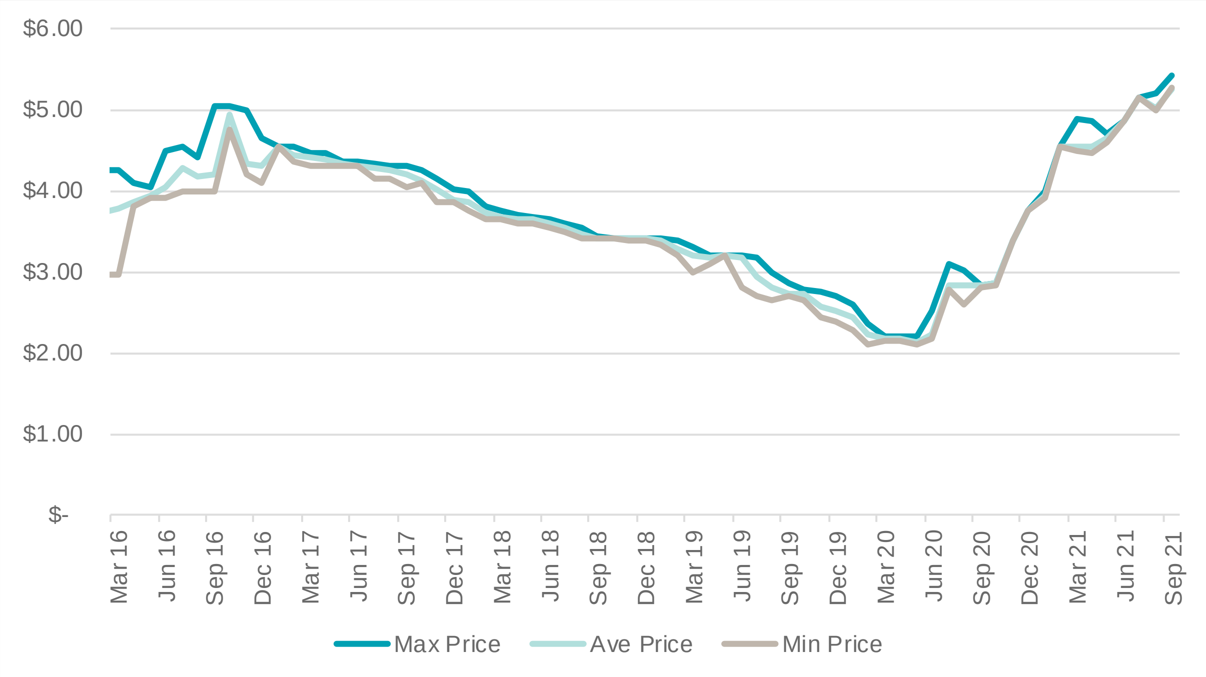
The gasTrading platform acts as an agent for the sellers of gas and operates a spot market. Each successful bidder receives gas based on its bid price and so the market does not clear at a single price. Each month the platform provides an indication of the quantity of gas available for sale over the 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 volume of gas is allocated.

The platform publishes maximum, average and minimum prices for the successful bids for each month. Figure 3 shows the historical prices for the gasTrading spot market.

30 Jacobs' report is available in Appendix 8.

31 Gas Trading Australia Pty Ltd, 2021, *Historical Prices and Volumes*, (online).

Figure 3. Historical gas price for trades in the gasTrading spot market



Source: gasTrading Australia (online).

Between August 2020 and August 2021, each month the platform has traded between 219 TJ and 608 TJ through the spot market. In its August 2021 invitation, the platform has announced 600 TJ (20 TJ per day) of available gas for supply during September 2021.[32]

The platform facilitates other trades than the spot market, for which the price information is not publicly available:

- "Off market" trade quantities are reported for transactions that are not part of the spot trades. It is not clear why these trades occur outside the spot market. Over the past 12 months the monthly quantity of gas traded off market varied between 405 TJ (observed in August 2021) and 1126 TJ.
- "Backup gas" trades that cover sales to unsuccessful bids in the spot market at a higher price than bid by those buyers. In correspondence to the ERA, gasTrading explained that prior to 2016/17 the backup gas mechanism was not needed because sellers had access to gas they had to pay for but could not use.
- "Firm gas" that facilitates contracts with firm access to gas.[33] However, no data is published on the volumes or prices of firm access gas traded.

Based on information available on gasTrading, the traded gas on this spot market is interruptible, with supply curtailments applying to the lowest price purchases first.[34] Given the order of access to gas through the platform, the highest bid price can be considered as a

32 gasTrading Australia, 2021, August 2021 – Invitation, (online).

33 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).*

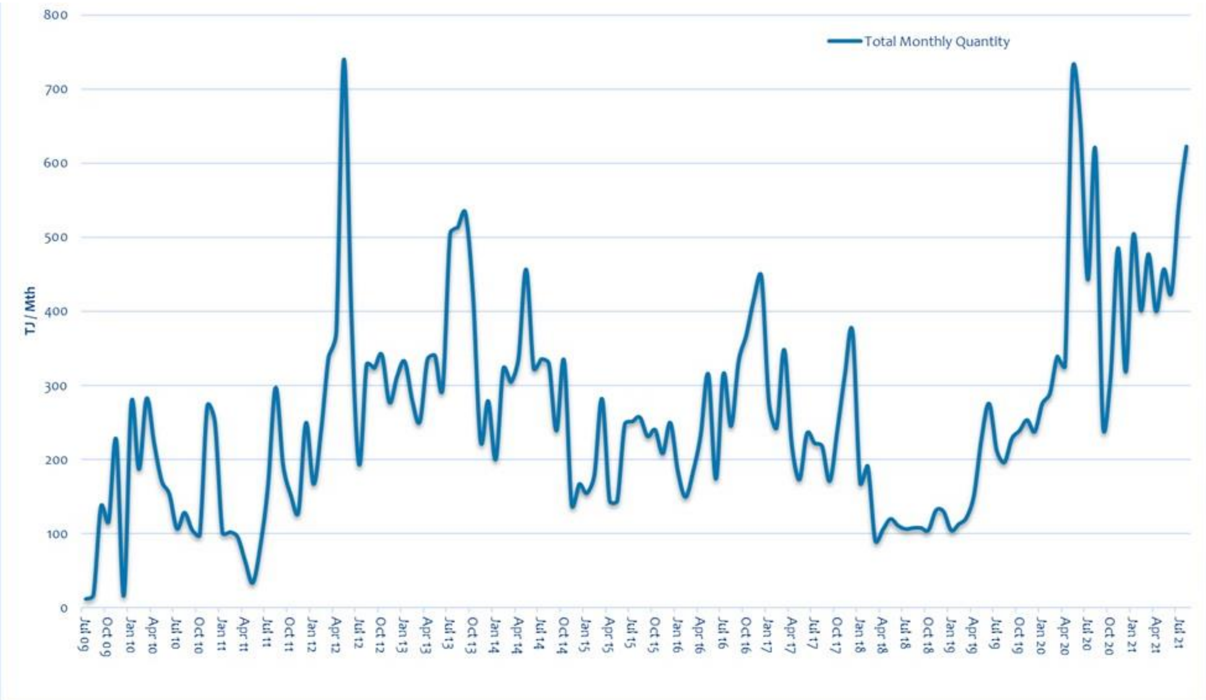
34 gasTrading Australia, 2021, Spot market – How it works, (online).

reasonable proxy for the price of firm access to gas. Jacobs used the historical monthly maximum spot prices to produce a forecast of future gas prices. AEMO's consultants previously used this approach to forecast gas prices to determine the price limits.

Minimum or average monthly prices 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 between relatively low (average $0.16/GJ). Information on back up gas price is not publicly available. During periods when a backup supply of gas has been provided, the backup price could be considered as the opportunity cost of gas because it could reflect the cost of supplying additional gas to meet demand.

The gasTrading spot market may not be a liquid market, and thus, a small increase or decrease in supply or demand may sharply influence cleared prices. Information is not available to assess the sensitivity of prices on the platform to small changes in demand and supply. For example, information is not available on the volume and prices for backup gas and firm gas products. One indication of possible illiquidity of the platform is the volume of trades.[35] The volumes traded on the platform have been a small proportion of the gas use for electricity generation in the SWIS and overall gas use in Western Australia. As shown in Figure 4, the monthly quantity of gas traded in the gas trading spot market has never exceeded 750 TJ.

Figure 4. Historical quantity of gas traded in the gasTrading spot market



Source: gasTrading, ([online](#)), accessed 22 September 2021.

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

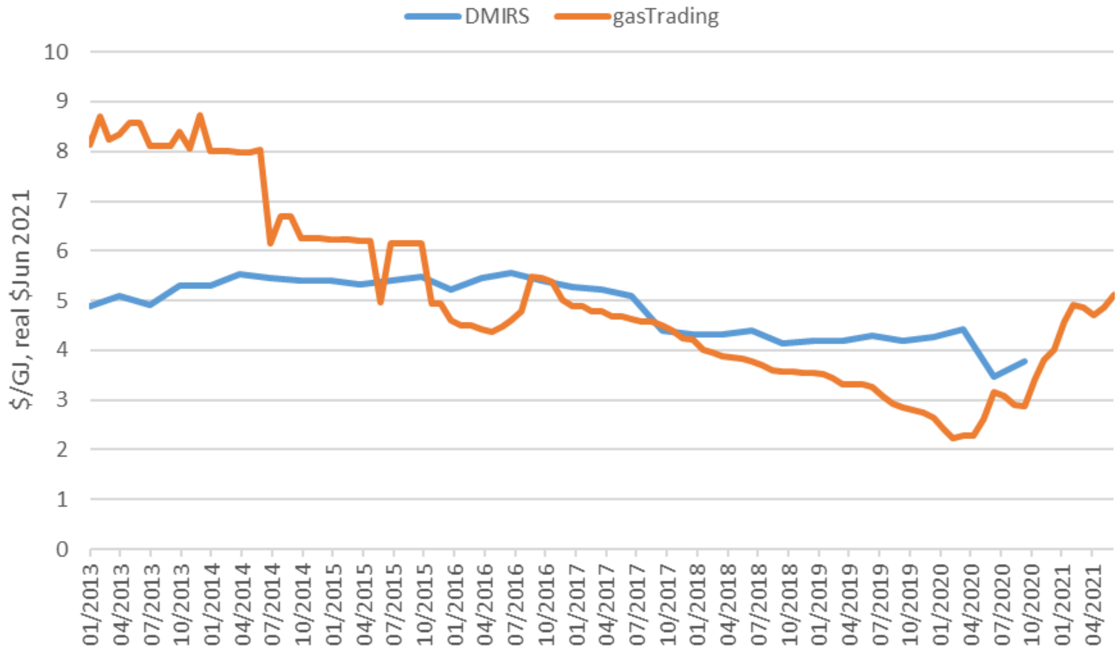
For comparison, over the past 10 years:

- The monthly average consumption of gas in Western Australia has been between 41,250 TJ and 55,750 TJ.[36]
- The monthly average consumption of gas for electricity generation in the SWIS has been between 5,800 TJ and 6,700 TJ.[37]

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.[38] This was particularly a concern because, at the time, gasTrading monthly maximum spot prices were substantially below the average prices published by DMIRS. The historical weighted average gas price published by DMIRS and monthly maximum spot prices in the gasTrading are depicted in Figure 5.

Figure 5. Historical volume weighted average gas price published by DMIRS and montly maximum spot prices in gasTrading



Source: DMIRS and gasTrading

DMIRS' quarterly price series represents the volume weighted average of gas prices by producers and is heavily weighted by bilateral contract prices, some of which expected to be

[36] AEMO, 2020, 2020 Western Australia gas statement of opportunities, December 2020, p. 17, (online).

[37] ACIL Allen, 2020, Gas Demand Review, Revised Final Plan Attachment, p.8, (online)

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

for firm gas supply.[39] After receiving feedback from stakeholders, AEMO used the DMIRS time series as the basis for calculating the fuel cost component of the energy price limits determination in 2020.

In its decision to approve AEMO's proposed revised values for the price limits in 2020, the ERA noted that:

- DMIRS price data had limitations because it lagged prevailing market conditions and did not include any information on bilateral sales between non-producers. The DMIRS price data also excluded any domestic gas sales that were not subject to the State royalty regime, such as domestic gas projects in Commonwealth waters and certain LNG facilities.

- Spot sales were likely to better reflect prevailing market conditions.

Despite the shortcomings of the DMIRS data, the ERA approved AEMO's proposed price limits for 2020 on the basis that it was the best available information available to AEMO. The ERA considered that there may be several appropriate and accepted ways to determine a particular input value. The ERA's role was to assess whether AEMO's proposal reasonably reflected the application of the method and guiding principles described in the WEM Rules.

For the gas price forecast, Jacobs considered the risk of using DMIRS data to project future price of gas given the current and expected conditions in the gas market. Jacobs explained that in 2021 spot gas prices have risen above DMIRS average prices, as shown in Figure 5. Given the expected lag in DMIRS price in reflecting prevailing market conditions, Jacobs considered the use of DMIRS data could result in under-forecasting gas prices over the next 12 months.

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

- If the spot market was illiquid, then observed prices reflected the lower boundary for the opportunity cost of gas.

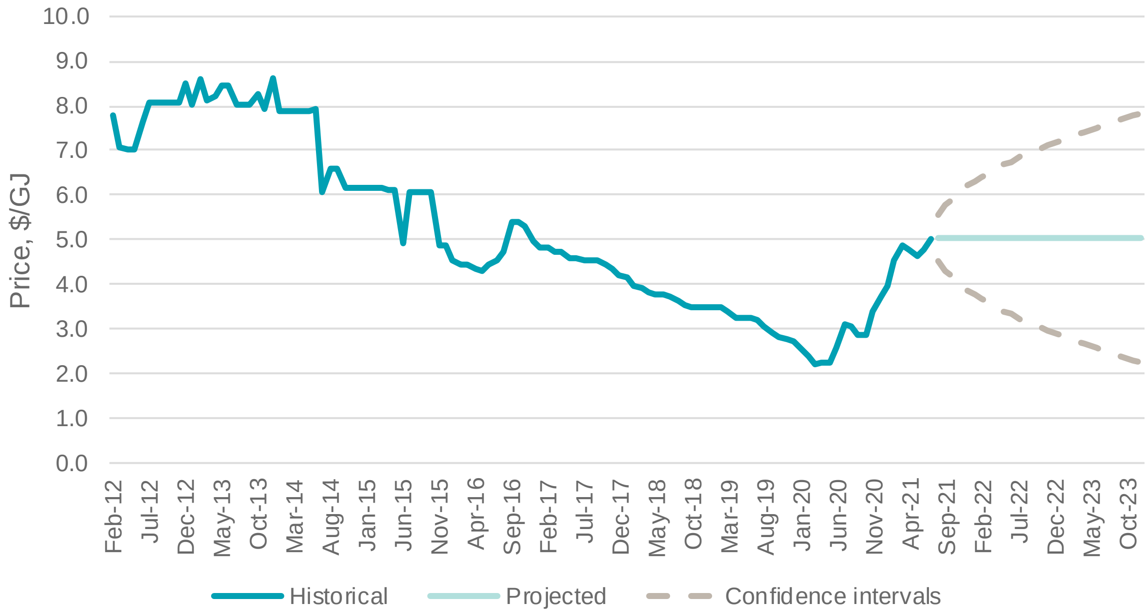
- Spot prices better reflected current market conditions.

- Spot price volatility was larger than that for DMIRS historical prices, contributing to a larger prediction band in projecting future gas prices. This could better address the risk of underestimating price limits.

Accordingly, Jacobs forecast the range of gas prices as of July 2021 with an expected value of \$5.04/GJ and standard deviation of \$0.63/GJ. Jacobs' forecast of gas price is depicted in Figure 6. The confidence intervals in Figure 6 are at 95 per cent level of confidence.

[39] 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.

Figure 6. Gas price forecast



Source: Jacobs, 2021, Gas price forecast, (Appendix 8 of this report).

2.3.1.1 Daily gas load factor

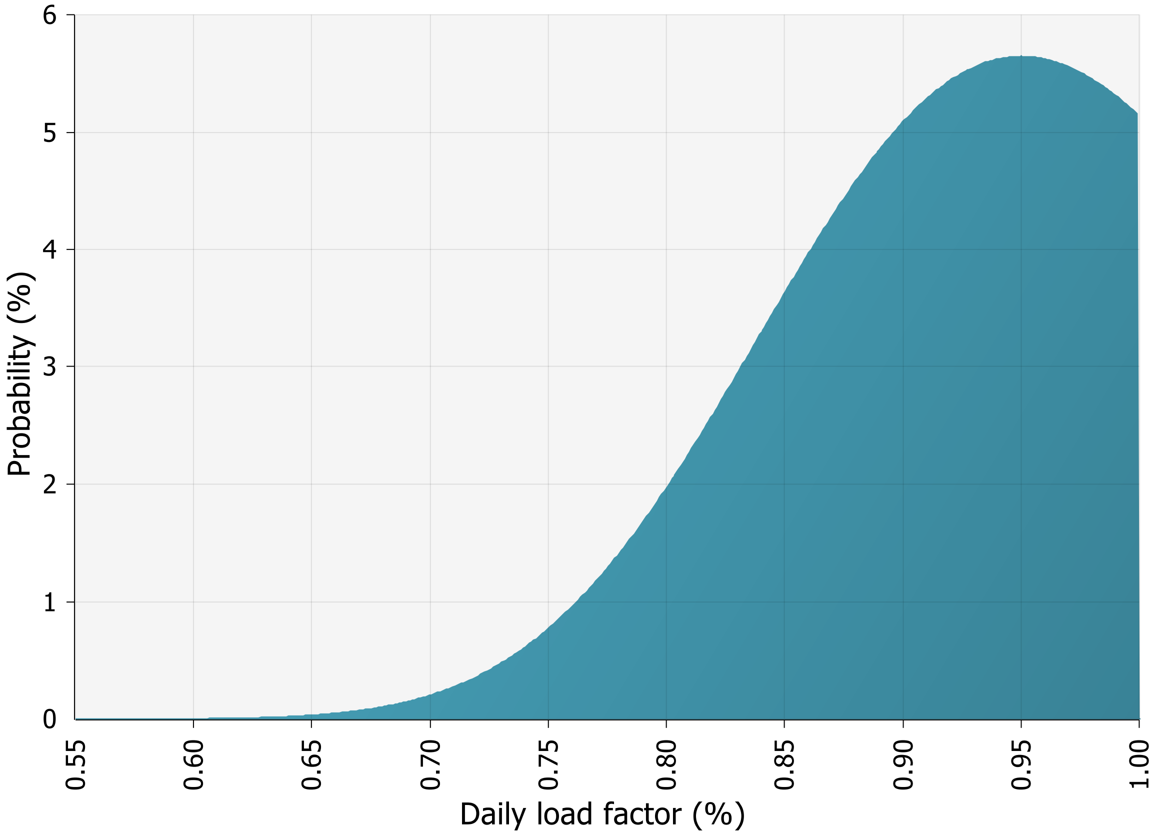
There is a risk that gas turbine generators over-estimate their consumption of gas for electricity generation when procuring gas and consequently pay for gas that they do not use. Previous reviews of the price limits accounted for this uncertainty by applying a gas load factor distribution to the gas price distribution. The method divides the gas cost by the loading factor (of average 0.8991).[40] This increases the gas cost by 11 per cent on average.

Consistent with the practice in previous reviews of the price limits, Jacobs suggested applying a probability distribution to represent the uncertainty of the daily gas supply load factor as shown in Figure 7. The mean of the composite daily load factor distribution is 89.91 per cent. This approach had been used in the price cap reviews from 2013 to 2018. The calculation of gas costs for Parkeston use the gas supply load factor distribution as recommended by Jacobs.

Further details about the application of the load factor are available in Jacobs' report in Appendix 8.

40 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.

Figure 7. Capped distribution for modelling uncertainty in spot gas daily load factor



Source: Jacobs, 2021, Gas price forecast, (Appendix 8 of this report).

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.[41] Some of the assets on the GGP are covered under the access regulatory regime of the *National Gas (Western Australia) Act 2009*.[42] 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 considered to be a non-scheme pipeline for which the regulator does not set regulated tariffs. The pipeline operator has published its own tariffs and terms for a set of standard non-reference services.[43]

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.

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

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

42 APA, 2021, Goldfields Gas Pipeline reference tariffs, (online).

43 APA, 2021, Website: tariffs and terms, accessed 11 November 2021, (online)

of any excess capacity available from those parties with existing contracts and the level of additional demand for transportation service on the pipeline.

Jacobs estimated possible gas transport costs to Parkeston based on reference service on the covered part of the pipeline and uncovered standard transport services, which are summarised in Table 2.[44]

Table 2. Estimated delivered gas price to Parkeston units, covered and uncovered tariffs

Item	Measure	Covered tariff	Uncovered tariff (used in the calculation of the price limits)
Undelivered gas price forecast ($/GJ)	Average	5.04	
	Standard deviation	0.63	
Transmission cost ($/GJ)	Average	1.39	4.56
	Standard deviation	0.15	0.15
Delivered gas price ($/GJ)	**Average**	**6.59**	**10.15**

Source: Jacobs, 2021, Gas price forecast, (Appendix 8 of this paper).[45]

Note: The estimate of gas price also uses a loading factor as explained in section 2.3.1.1.

In estimating a delivered price of gas for Parkeston units as part of determining the price limits, the ERA considered upper and lower boundaries for the opportunity cost of gas.

The lower bound of the opportunity cost of gas is based on the assumption that there is large unused gas and transport capacity available from those parties with existing transportation contracts and limited demand for additional gas transport. For sellers, their cost of procuring transport capacity and gas is sunk, and so the opportunity cost of delivering gas is close to zero.

The ERA is aware that there is currently limited to no uncontracted capacity available in the covered or uncovered pipeline[redacted].[46] It is possible that some capacity becomes available over the next year if parties terminate their existing contracts. However, the availability of any capacity released from these contracts and service prices would be subject to possible auctions for transport

44 To account for the uncertainty in transmission costs, the ERA's consultant assumed the minimum spot price for the uncovered capacity on the GGP is normally distributed with a mean value of $4.564/GJ and a standard deviation of $0.15/GJ (refer to Appendix 8).

45 Jacobs concluded its review for the ERA in September 2021. At the time of drafting this paper (October 2021), the ERA was also reviewing an application from Goldfields Gas Transmission to approve an annual reference tariff variation for the GGP. The ERA's final determination of the energy price limits will consider any approved reference tariff variations.

46 [redacted] In its report to the ERA, Jacobs explained that the covered portion of the GGP was understood to be at capacity, and therefore it was unlikely that a spot service could presently be negotiated. Information available on the GGP's operator website also shows that uncovered capacity is unavailable for contracting until the end of 2022. See Appendix 8 for Jacobs' report and APA, 2021, *Goldfields Gas Pipeline, service availability information, 36-month uncontracted capacity outlook*, (online). In the previous review of the price limits in 2020, Alinta Energy provided feedback to AEMO that there was no spot transportation capacity available on the GGP and Parkeston units were likely to pay for uncovered tariffs for transportation. See: Alinta, 2020, *Submission to AEMO's 2020 energy price limits review*, p. 2, (online).

capacity or negotiations between gas consumers, like Goldfields Power, and the pipeline operator. Therefore, the lower bound of the opportunity cost of sourcing gas for Goldfields Power in the current market is likely to be higher than zero.

The upper bound of the opportunity cost of gas is set by the cost of alternative fuel – distillate. If the availability of pipeline capacity is so limited that the price of available capacity increases the overall cost of gas beyond the cost of distillate, then buyers like Goldfields Power would opt out of the gas market and instead purchase distillate to generate electricity.

The lower and upper boundaries create a range of possible gas opportunity costs and the ERA has determined an opportunity cost of gas for Goldfields Power within this range after taking all relevant considerations into account, as explained below and in section 2.3.1. The determination allows for 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 practice, the price in a gas delivery contract can vary between the seller's and buyer's reservation price – which is the minimum price sellers are willing to accept, and the maximum price buyers are willing to pay. The level of price varies depending on the buyer's and seller's negotiation power. For the Parkeston units, Goldfields Power would not be willing to buy gas at a price more than the cost of liquid fuel. It is therefore possible that Goldfields Power's fuel cost varies in the coming year depending on the availability of sellers with excess gas and the number of consumers seeking access to transportation capacity. [redacted] that [redacted]

Determining the supply cost of the Parkeston units – and thus the price limits – based on covered transportation tariffs can result in regular switching of dual fuel capable Parkeston units to liquid fuel [redacted]

If the price cap is set low – that is, based on the lower covered transportation cost – it is possible that Goldfields Power may not be able to recover its supply cost when offering to the balancing market. This is because its delivered gas cost could exceed that used in the determination of the price caps. [redacted]

Setting the price caps too low can increase the supply cost of energy, risk greater inefficiencies in the market and is not consistent with the objectives of the WEM Rules. Gas prices including uncovered transport tariffs are significantly lower than liquid fuel cost, which is currently estimated as approximately $23/GJ (section 2.3.3).

To determine the price limits in this draft determination, the ERA used the delivered gas price based on the uncovered transport charge on the GGP. Using the uncovered tariff instead of the covered tariff will result in a higher fuel cost input into the price limits calculation, resulting in a higher maximum STEM price being calculated. For the estimation of the price limits, this report uses the gas price and transportation cost figures for Parkeston units as shown in the 'uncovered tariff' column of Table 2.

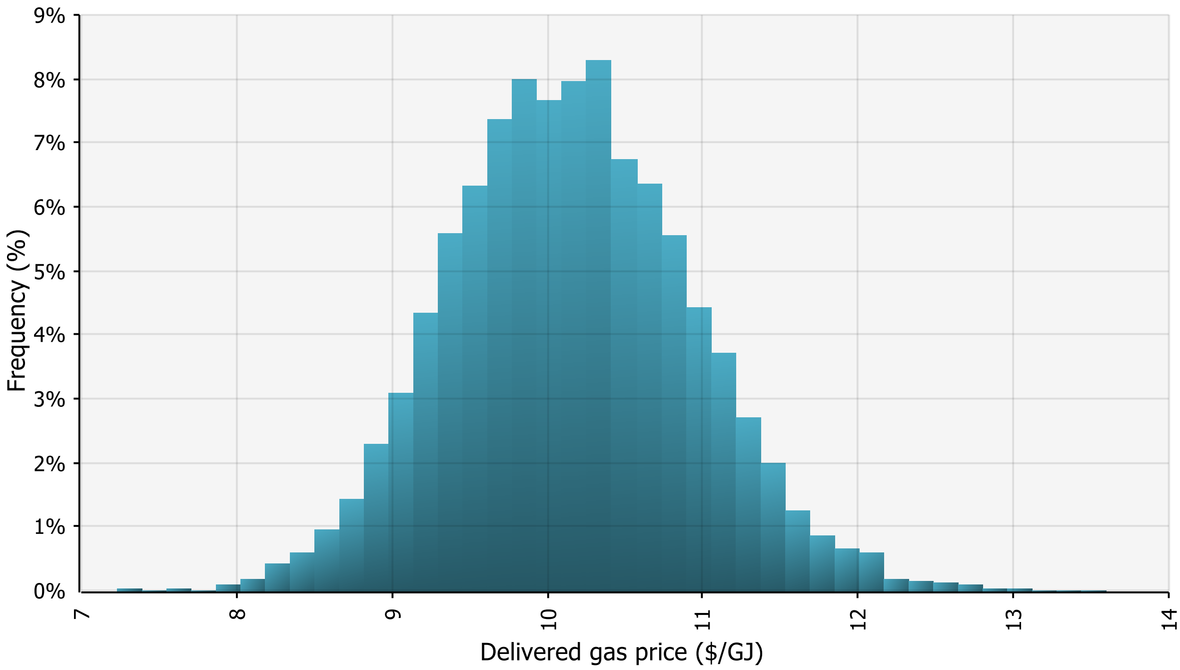
Setting the price cap based on a very high delivered gas price – for example as high as the cost of distillate (which is currently estimated as $23/GJ) – is not reasonable because setting the price limits based on a gas price very close to distillate price would result in the maximum STEM price and the alternative maximum STEM price being very similar. This can reduce the effectiveness of the maximum STEM price in mitigating the exercise of market power in the WEM.

In landing on a gas transportation cost to include in the energy price limits calculation, the ERA considered the available capacity and supply and demand conditions on the pipeline. The ERA determined that a gas transportation forecast of $4.564/GJ was 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 the coming year, if evidence emerges that the delivered gas costs to the Parkeston units is 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 resulting distribution of delivered gas price is shown in Figure 8, which also includes the application of the gas load factor distribution explained in section 2.3.1.1.

Figure 8. Distribution of delivered gas price, Parkeston units



Source: ERA analysis of data from Jacobs and Goldfields Power, 2021.

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

2.3.3 Distillate price

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

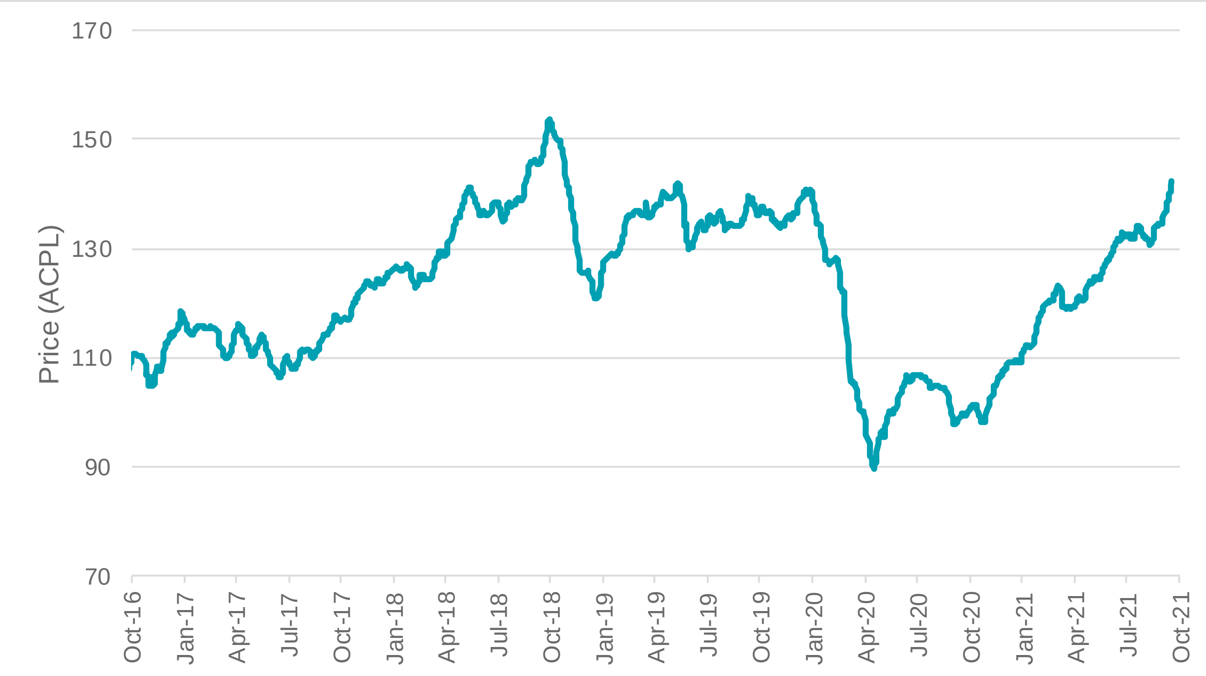
The ERA has based its estimate of distillate using the Perth diesel TGP, consistent with the approach taken in previous reviews. Therefore, in this analysis a reference distillate price based upon the Perth diesel TGP is assessed to define a benchmark alternative maximum STEM price component that depends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

For the purpose of the ERA's review of the price limits, the uncertainty in the distillate price is not important because the alternative maximum STEM price is indexed to the distillate price and updated monthly. However, in modelling the gas price for the maximum STEM price, the uncertainty and level of the distillate price is relevant to the extent that it is used to cap the extreme gas prices at the level where the dispatch cycle cost would be equal for gas and for distillate firing for the nominated gas turbine technology and location. This cost parity is considered to create a cap for the distribution of gas price 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. The prices have mostly recovered over the last 12 months to October 2021 as shown in Figure 9.

The September 2021 edition of the United States Energy Information Administration's (EIA) Short-Term Energy Outlook highlighted the heightened levels of uncertainty related to the ongoing recovery from the pandemic.[47] The EIA outlined that Brent crude oil prices rose over the past year as result of steady draws on global oil inventories. The EIA considered that Brent prices would remain near current levels for the remainder of 2021.

Figure 9. Perth diesel daily average terminal gate price



Source: Australian Institute of Petroleum, 2021, (online).

Note: ACPL is Australian cents per litre.

The ERA undertook the following approach to derive the reference distillate price:

1. Take the latest Perth TGP (as at 15 October 2021).

[47] US Energy Information Administration, September 2021, *Short-Term Energy Outlook*, (online).

2. Remove the GST and diesel excise that would not be paid by local generators.

3. Convert the cost of distillate from Australian cents per litre (ACPL) to $/GJ.

The outputs are shown in Table 3 below.

Table 3. Reference distillate price for Parkeston and Pinjar units

Item	ACPL	$/GJ (b)
Ex terminal price (as at 1 October 2021) [a,b]	149.30	38.68
Ex terminal price less excise [c]	104.19	26.99
GST	10.42	2.70
Ex terminal price less GST and excise	**93.77**	**24.29**

(a) Australian Institute of Petroleum, 2021, (online).
(b) 1 Litre of diesel fuel is equivalent to 38.6 MJ, (online).
(c) Diesel excise is $0.433/litre from 2 August 2021, (online).

The price of distillate will vary due to fluctuations in world oil prices and refining margins. Over the coming year AEMO will use prevailing delivered distillate price to Parkeston to reset the alternative maximum STEM price using the formula determined in this paper (refer to section 3.2).

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 generator to generate one megawatt hour 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 but do not define any method for determining this variable. Previous reviews of the price limits until 2018 inferred a distribution for minimum capacity based on observed dispatch of candidate units. The mean heat rate at minimum capacity estimated in this paper is larger than that estimated for Pinjar and Parkeston in recent reviews of the price limits.

In 2019 and 2020, AEMO's consultant Marsden Jacobs calculated the mean heat rate for the Pinjar and Parkeston units as functions of average generation output observed in the past.[48] Marsden Jacobs reported a mean heat rate of 20.62 GJ/MWh and 19.19 GJ/MWh for the Pinjar units in 2019 and 2020 respectively, which were reasonably close to the average heat rate of these machines at minimum stable generation limit. This result is expected because the Pinjar units have often dispatched close to their minimum stable generation over the last few years. Previous reviews of the price limits reported similar heat rates for Pinjar to those used by Marsden Jacobs. This is explained in Appendix 4.

Marsden Jacobs previously reported average heat rates at minimum capacity of 13.85 GJ/MWh and 15.31 GJ/MWh in 2019 and 2020 respectively for the Parkeston units. However, these heat rates are [redacted] than the average heat rate for these machines at their minimum stable generation level of [redacted]. This result is expected because the Parkeston units have often dispatched at output levels that are higher than their minimum stable generation

[48] Marsden Jacobs, 2020, *2020-21 Energy price limits review, Final report*, p. 46, (online).

level and the previous reviews based their estimate of heat rates on observed historical dispatch. Determining an average heat rate based on observed historical dispatch resulted in estimates of fuel costs substantially below that expected at the minimum stable generation level of these units.

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 minimum stable generation. When using historical dispatch information, it is important to consider the calculation uses a reasonable minimum capacity distribution that is in line with the intention of the price limits.

The ERA drew on methods used in previous reviews of the price limits and made improvements to the calculation to ensure that the mean heat rate used in the calculation better reflects the high-cost conditions of the machines typically expected to happen around the minimum stable generation of plants. AEMO's consultant previously estimated the minimum capacity of the generating units based on the lower half of the range of observed output of these units. To determine the minimum capacity, the ERA has instead considered observed output levels closer to the Parkeston units' minimum stable generation level.

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). The ERA also received an average heat rate curve for the Parkeston units.

The ERA's method to determine heat rate at minimum capacity can be summarised as follows:

- Review the historical output level of the candidate machines to infer a distribution for the minimum capacity of the units. This is generally consistent with the approach adopted in previous reviews of the price limits and is further explained in Appendix 4. However, the ERA amended the approach to ensure the calculated range for minimum capacity distribution better reflects the minimum stable generation of units.
- For the Parkeston units:
  - Assume the minimum capacity is normally distributed with a mean of 8.13 MW and a standard deviation of 3.33 MW. The average of the distribution is comparable to the units' minimum stable generation level of [redacted].
  - 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 mean of the distribution of the heat rate at minimum capacity is 24.0 GJ/MWh. This is substantially higher than the mean heat rate at minimum capacity for Parkeston estimated in previous reviews (15.31 GJ/MWh in the 2020 review).
- For the Pinjar units:
  - Assume the minimum capacity for Pinjar is normally distributed with a mean of 10.1 MW and a standard deviation of 0.6 MW. The average of the distribution is comparable to the units' minimum stable generation level of [redacted].
  - Use the distribution of minimum capacity as an input into the heat rate curves provided by Synergy to derive a distribution of heat rates at minimum capacity.
  - Choose the higher of the two heat rate distributions provided by Synergy (for 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.

– The mean of the distribution of the heat rate at minimum capacity is 21.5 GJ/MWh. This is slightly higher than the mean heat rate at minimum capacity for Pinjar estimated in previous reviews (19.19 GJ/MWh in the 2020 review).

This increase in average heat rate at minimum capacity for the Parkeston units has contributed in the Parkeston units becoming the highest cost generator for setting the price limits.

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 bus-bar.[49]

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. An increase in the loss factor will reduce the price limits and vice versa (holding all other variables constant).

The WEM Rules require Western Power to annually calculate the loss factor for each connection point in its network and provide these values to AEMO.[50] Western Power determined the following loss factors to apply from 1 July 2021:

Table 4. 2021/22 loss factors, Pinjar and Parkeston units

Facility	Loss factor
Parkeston	1.1322
Pinjar	1.0229

Source: Western Power, 2021, 2021/22 Loss Factor Report, *(online).*

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.

49 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).

50 Wholesale Electricity Market Rules, 1 October 2021, clause 2.27, (online).

In previous reviews of the energy price limits, AEMO's consultant generated distributions of the variable parameters in the calculation and determine 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.
- The ERA has followed the same approach as previous years in calculating the risk margin.

It is important to note that the value of risk margin applied 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 is 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.[51]

Monte Carlo simulation performs risk analysis by building models of possible results by substituting a range of values – a probability distribution – for any factor that has inherent uncertainty. It then calculates results in numerous sampled iterations, each time using a different set of randomly sampled values from the input probability distributions. The ERA used 10,000 simulation iterations in this review.

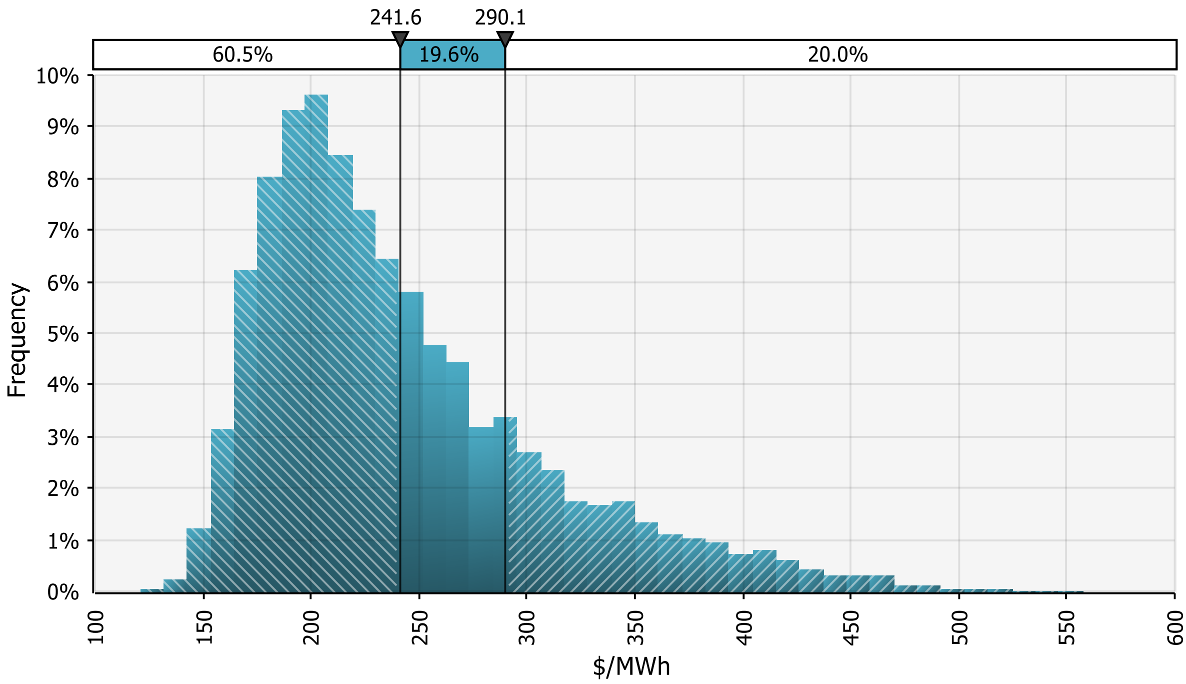
3.1 Maximum STEM price

Table 5 shows the estimates of the input factors and the proposed maximum STEM price. Figure 10 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 $290/MWh.

[51] 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.

Figure 10. Average variable cost distribution, Parkeston units



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

Table 5. Calculation of the maximum STEM price, Parkeston units

Component	Unit	Proposed value – 2021	Determined value – 2020
Mean variable O&M cost	$/MWh	30.1	110.5
Mean heat rate at minimum capacity	GJ/MWh	24.0	19.2
Mean fuel cost	$/GJ	10.1	7.0
Loss factor	-	1.1322	1.0274
Mean of the average variable cost distribution	$/MWh	241.6	238.9
80th percentile of the average variable cost distribution	$/MWh	290.1	267.1
Risk margin	%	19.6	11.8
Maximum STEM price	**$/MWh**	**290**	**267**

Note: *The values determined in 2020 and proposed in 2021 are not directly comparable as the 2020 values are based on the Pinjar units whereas the 2021 values are based on the Parkeston units.*

Note: *Proposed 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 Parkeston units have replaced the Pinjar units as the highest cost generator for setting the price limits. This shift is largely driven by two factors:
  - The substantial increase in the estimate of heat rate at minimum capacity for Parkeston (from an average of 15.3 GJ/MWh in 2020 to 24.0 GJ/MWh in 2021).
  - The substantial decrease in the estimate of VOM cost for Pinjar (from $110/MWh in 2020 to $40/MWh in 2021).
- The estimated mean VOM cost for the Parkeston units ($30/MWh) is substantially lower than that estimated for Pinjar last year ($110/MWh). The ERA's estimate of VOM costs this year is informed by information received from asset owners. In comparison, AEMO's estimate of VOM costs was reliant on information voluntarily provided by asset owners or available publicly.
- The estimated mean fuel cost component of the calculation is larger than the 2020 estimate. This is mainly due to variance in both the base gas price and gas transportation cost:
  - The fuel cost for Parkeston contains a larger transportation cost ($4.564/GJ) when compared to fuel transport cost estimated for Pinjar last year ($1.557/GJ).
  - The average price of gas used this year ($5.04/GJ) is also larger than that used last year ($4.09/GJ). The fuel cost input in last year's review was based on average gas prices from DMIRS whereas the ERA's review this year used spot prices from gasTrading.
- The loss factor for Parkeston is generally larger than that for Pinjar. The analysis uses the loss factor provided by Western Power. The larger the loss factor, the lower the assessed price cap.
- The average of the distribution of average variable cost for Parkeston this year is slightly larger than that for Pinjar estimated last year.
- The distribution of average variable cost for Parkeston has a larger range when compared to that for Pinjar last year. The 80th percentile of the distribution for Parkeston is 20 per cent larger than the average of the distribution. The risk margin included in the price cap is larger than that derived last year.

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 below:

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

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 maximum STEM price. A linear regression is then applied using the sampled distillate price as independent variable and sampled alternative maximum STEM price as dependent variable. This method is summarised as below:

1. Use the same model developed for the estimation of maximum STEM price.
2. Use a range of distillate price as fuel cost input to the model.
3. Determine 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 on the range of distillate price used as independent variable and estimated alternative maximum STEM price as 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.

For clarity, the road freight cost of distillate is not included in the fuel component as it is considered that this price is largely independent of the price of distillate. The road freight component is therefore reflected in the non-fuel coefficient.

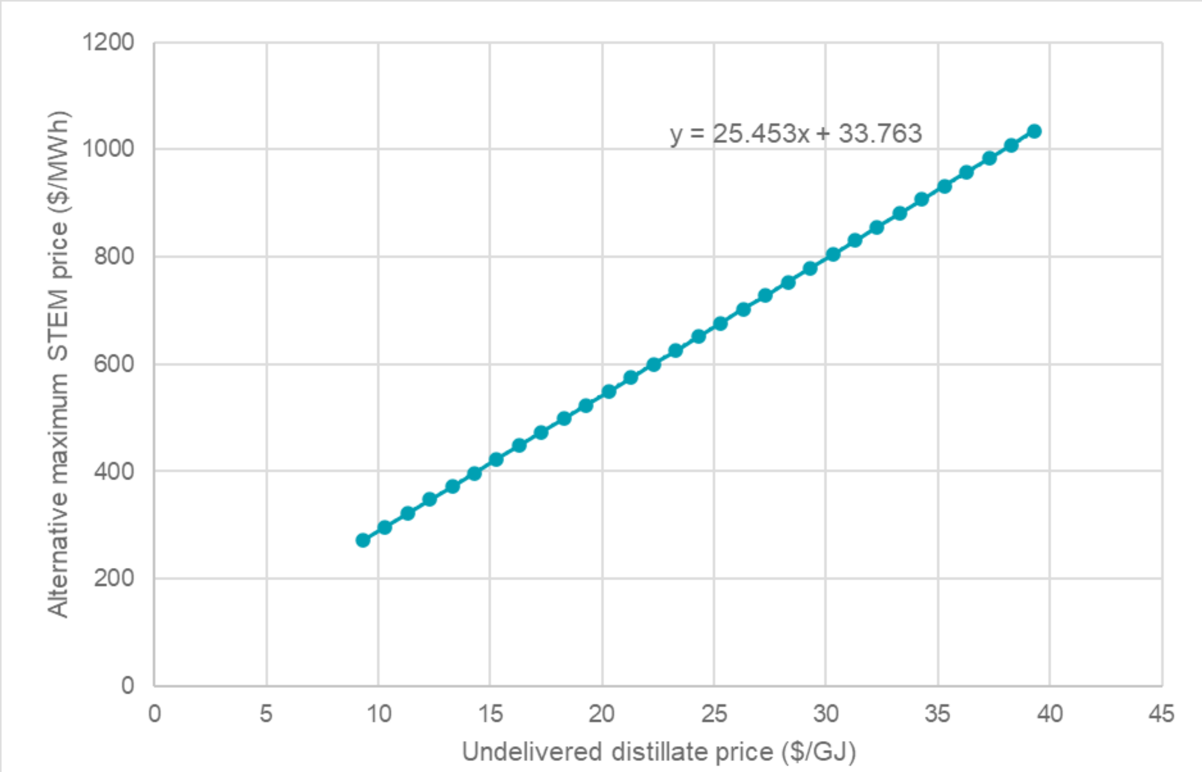
The estimated indexation formula for the alternative maximum STEM price is as below:

$$\begin{aligned} &alternative\ maximum\ STEM\ price \\ &\qquad = 33.763 + 25.453 \times net\ ex\text{–}terminal\ distillate\ price\ (\$/GJ) \end{aligned}$$

The estimated regression function is shown in Figure 8.

At the current distillate price of $24.3/GJ, the ERA's revised indexation formula yields a higher value for the alternative maximum STEM price of $652/MWh, when compared to $607/MWh based on the formula determined last year.

Figure 11. Proposed alternative maximum STEM price based on range of distillate prices, Parkeston units



Appendix 1 The ERA's obligations under the WEM Rules

The following excerpts from the WEM Rules outline the ERA's obligations to determine the energy price limits.

6.20. Energy Price Limits

6.20.1. The Energy Price Limits are:

(a) the Maximum STEM Price;

(b) the Alternative Maximum STEM Price; and

(c) the Minimum STEM Price.

6.20.2. The Maximum STEM Price is the value published on the WEM Website and revised in accordance with clauses 6.20.6 and 6.20.11.

6.20.3. Subject to clause 6.20.11, the Alternative Maximum STEM Price is to equal:

(a) from 8 AM on September 1, 2006, $480/MWh; and

(b) from 8 AM on the first day of each subsequent month the sum of:

i. $440/MWh multiplied by the amount determined as follows:

1. the average of the Singapore Gas Oil (0.5% sulphur) price, expressed in Australian dollars, for the three months ending immediately before the preceding month as published by the International Energy Agency in its monthly Oil Market Report, or the average of another suitable published price as determined by AEMO, divided by;

2. the average of the Singapore Gas Oil (0.5% sulphur) price, expressed in Australian dollars, for May, June and July 2006 or, if a revised Alternative Maximum STEM Price takes effect in accordance with clause 6.20.11, for the three months ending immediately before the month preceding the month in which the revised Alternative Maximum STEM Price takes effect, as published by the International Energy Agency in its monthly Oil Market Report, or the average of another suitable published price as determined by AEMO; and

ii from 8 AM on September 1, 2006, to 8 AM on 1 September, 2007, $40/MWh, and for each subsequent 12-month period $40/MWh multiplied by the CPI for the June quarter of the relevant 12-month period divided by CPI for the 2006 June quarter or, if a revised Alternative Maximum STEM Price takes effect in accordance with clause 6.20.11, the June quarter of the year in which the revised Alternative Maximum STEM Price takes effect, where CPI is the weighted average of the Consumer Price Index All Groups value of the eight Australian

State and Territory capital cities as determined by the Australian Bureau of Statistics;

rounded to the nearest whole dollar, where a half dollar is rounded up, with the exception that from the date and time that a revised Alternative Maximum STEM Price takes effect in accordance with clause 6.20.11, the revised values supersede the values in 6.20.3(b)(i) and 6.20.3(b)(ii), and are to be the values used in calculating the Alternative Maximum STEM Price for each month subsequent to the month in which the revised Alternative Maximum STEM Price takes effect.

6.20.4. [Blank]

6.20.5. [Blank]

6.20.6. The Economic Regulation Authority must annually review the appropriateness of the value of the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.7. In conducting the review required by clause 6.20.6 the Economic Regulation Authority:

(a) may propose revised values for the following:

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

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

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

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

Where

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

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

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

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

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

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

6.20.8. [Blank]

6.20.9. In conducting the review required by clause 6.20.6 the Economic Regulation Authority must prepare a draft report describing how it has arrived at a proposed revised value of one or both of the Maximum STEM Price and Alternative Maximum STEM Price. The draft report must also include details of how the Economic Regulation Authority determined the appropriate values to apply for the factors described in clauses 6.20.7(b)(i) to 6.20.7(b)(v). The Economic Regulation Authority must publish the draft report on the WEM Website and advertise the report in newspapers widely published in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users, within six weeks of the date of publication.

6.20.9A. Prior to proposing a final revised value for one or both of the Maximum STEM Price and Alternative Maximum STEM Price in accordance with clause 6.20.10, the Economic Regulation Authority may publish a request for further submissions on the WEM Website. Where the Economic Regulation Authority publishes a request for further submissions in accordance with this clause, it must request submissions from all sectors of the Western Australia energy industry, including end-users.

6.20.10. The Economic Regulation Authority must consider in-time submissions on the draft report described in clause 6.20.9, and any in-time submissions received under clause 6.20.9A, and may consider any late submissions, and after considering the submissions must propose a final revised value for one or both of the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.11 A proposed revised value for the Maximum STEM Price and the Alternative Maximum STEM Price replaces the previous value after AEMO has posted a notice on the WEM Website of the new value of the applicable Energy Price Limit, with effect from the time specified in AEMO's notice.

Appendix 2 Variable operating and maintenance (VOM) cost for the Pinjar units

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

In previous reviews of the price limits, AEMO's consultants developed methods to account for VOM costs, having consideration for the maintenance planning methods provided by the original equipment manufacturer of the gas turbines. Generally, the method calculates 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 did not use Synergy's estimate of VOM costs for the Pinjar units. The reasons for this are explained further below.

The ERA has used a similar approach to those used in the previous reviews of the price limits to estimate VOM costs for the Pinjar units. This approach uses Synergy's estimate of maintenance expenditures for Pinjar. 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 further below.

The discounted cost per start is converted to a discounted cost per MWh of electricity generated based on the possible duration of short dispatch cycles. The choice of short dispatch cycles for this conversion ensures the estimated cost per start is spread over a shorter period of time, and hence, the estimated cost per unit energy generated reflects 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 in Appendix 4.

Review of underlying maintenance costs

Similar to the approach adopted in previous reviews of the price limits, this paper considers the following costs as material and includes them in the calculations of VOM costs:

- Variable maintenance costs, which are the cost of conducting periodic maintenance work required to maintain the generating unit in an efficient and reliable condition. These costs mainly comprise maintenance service, parts and labour expenses.

- Consumable and waste related costs that include raw water cost, waste and wastewater disposal expenses, chemical, catalysts and gases, lubricants, and consumable materials and supplies costs.

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.[52] 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).[53]

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. This is explained in more detail in Appendix 4.

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:[54]

- 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.

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. This is explained in detail in Appendix 4.[55]

As shown in Table 6, the ERA received information from GE and Synergy for estimates of maintenance costs. The ERA compared these costs:

- The cost estimates provided by GE were typical estimates for Frame 6B turbines like Pinjar and were larger than those provided by Synergy.
- AEMO's estimate of maintenance expenditures in recent reviews of the price limits were larger than those provided by Synergy to the ERA. Jacobs, AEMO's consultant, last reviewed maintenance expenditures in detail in 2015 based on information from the equipment manufacturer.[56] After 2015, reviews of the price limits escalated those estimates based on consumer price index and exchange rate changes.

The calculation of the price limits in this review uses Synergy's estimate of variable maintenance expenditures as the basis of the determination of VOM costs. The ERA considered that Synergy's estimate as the asset owner better reflect the specific costs for the Pinjar units.

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

53 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.

54 GE's manual also advises a replacement of rotor after 5,000 factored starts. Given the expected number 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. Recent reviews of the price limits did not include rotor replacement costs.

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

56 Jacobs, 2015, *Energy price limits for the Wholesale Electricity Market in Western Australia*, p. 33, (online).

Table 6. Comparison of estimates of maintenance and overhaul costs, Pinjar units

	Synergy	GE	AEMO
Source	Asset operator	Original equipment manufacturer for typical Frame 6B turbines	Previously conducted the review
Dollar values as of	2021	2021	2015
Type A	[redacted]	Not provided	1,348,773
Type B	[redacted]	Approximately 350,000 for Frame 6B turbines	4,517,420
Type C	[redacted]	Approximately 850,000 for Frame 6B turbines	4,138,774
Capital parts	[redacted]	For Type B: Approximately $350,000 for repair of parts or $3 million for new parts. For Type C: Approximately 480,000 for repair of parts or $3.8 million for new parts.	Overhaul costs above include capital parts costs. They assume 75 per cent of parts are repaired and 25 per cent of parts are replaced.

Note: The values provided by Synergy exclude:

1. *expenditure items the ERA considers as fixed maintenance expenditures*
2. *rotor replacement, that Synergy estimated to cost [redacted]. Given the expected number 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. AEMO adopted this approach to estimate VOM costs in previous reviews of the energy price limits.

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. This method is explained briefly via a numerical example in the explanation box 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.[57] For clarity, the calculation of the price limits in this review uses Synergy's estimate of maintenance expenditures, 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.[58] 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 8is 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 accounts 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.

In response to the ERA's request for information, Synergy provided its estimate of VOM costs, expressed per start of units. The ERA considers that Synergy did not use a reasonable method to estimate its VOM costs, which resulted in Synergy over-estimating its cost per start. The reasons for the ERA's determination are as follows:

- Synergy did not consider that maintenance expenditures occur in future periods and instead assumed all maintenance expenditures happen all at once in present time.
- Synergy also did not consider that some maintenance works happen more than once in a maintenance cycle.
- Synergy's estimate did not exclude some maintenance expenditures that are unrelated to the number of starts or the generation output of the plant. The ERA considers that maintenance expenditure that do not vary with the generation of the machine must be excluded from the calculation of the price limits.[59] Previous reviews of the price limits also

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

[58] 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.

[59] The Reserve Capacity Mechanism in the SWIS allows for including fixed O&M costs in the pricing of capacity credits. ERA, 2020, *Market procedure, benchmark reserve capacity price, version 7,* paragraph 2.5, (online).

did not include fixed operating and maintenance expenditures in the estimation of price limits.

The ERA estimated VOM costs for the Pinjar units, expressed in dollars per start, using Synergy's estimate of variable maintenance expenditures and a variant of the method for spreading maintenance expenditures over each start of units, as explained above. The method used did not include any assumption for the expected end of life for Pinjar units. This is because:

- Using an end-of-life assumption may result in Synergy not being able to recover its VOM costs incurred in prior years, because Synergy did not use an estimation method consistent with that presented above. The ERA's analysis showed VOM costs for the Pinjar units would be negligible if an end-of-life assumption is considered because hardly any variable maintenance expenditure is likely to occur before the expected retirement of the units in [redacted]. [redacted]

- The ERA does not have any information on the current maintenance status of Pinjar units. Despite the ERA's request, Synergy did not provide any information when the last major maintenance works (types A, B and C) were conducted.

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.[60] This approach is similar to the approaches adopted by AEMO's consultant, Jacobs, in previous reviews of the price limits.[61]

- A real pre-tax weighted average cost of capital (WACC) of 3.46 per cent per year, to estimate the present value of expected variable maintenance expenditure. This is based on a nominal pre-tax WACC of 5.45 per cent calculated by the ERA.[62,63] 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 53.1 starts per year. The maintenance factor used are 1.07 for maintenance type A and 0.68 for maintenance type B and C. These are explained in detail in Appendix 4.

60 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.

61 For example, in the 2017 review of the price limits Jacobs assumed Pinjar units were at an average point in time across maintenance cycle and spread all future maintenance over a remaining 20 year life. In the 2018 review, Jacobs assumed a full maintenance cycle (of 44 years) for Pinjar when estimating VOM costs, as determined by the expected number of starts. Refer to Jacobs, 2017, *Energy price limits for the Wholesale Electricity Market in Western Australia*, p. 30, (online) and ERA, 2018, *2018 Energy price limits decision*, pp. 10–11, (online).

62 The calculation of real WACC considered an average inflation forecast of 1.92 per cent per annum using the Reserve Bank of Australia's estimated inflation rate. RBA, 5 October 2021, *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).

63 ERA, 2021, *Benchmark reserve capacity price for the 2024-25 capacity year – Draft determination*,(online).

Results

For the Pinjar units the estimated average VOM cost expressed as a cost per start is [redacted]. In comparison, Synergy's estimated VOM cost for Pinjar is [redacted] per start. This revised value is also lower than the point estimate of maintenance costs of [redacted] provided by Synergy to AEMO for the 2020 review of energy price limits.[64]

In previous reviews, fuel start-up costs have been factored into the generator's heat rates. In this review, the ERA has considered the start-up fuel cost as part of the VOM cost.[65]

Synergy provided that the Pinjar units require [redacted] of gas to start up. Based on a gas price of [redacted] and transmission cost of [redacted] (distribution) as explained in Appendix 3, the ERA estimated an average of [redacted] (distribution) of start-up fuel consumption.

The estimated VOM costs per start are converted to dollar per MWh or energy generated using the method explained in section 2.2.2.

For the review this year, the mean VOM cost for Pinjar is $40/MWh, which is considerably lower than the estimate of $110/MWh in last year's review.

The estimation method and main factors used are summarised in Table 9.

64 Marsden Jacob, *2020, 2020-21 Energy Price Limits Review – Final Report*, p. 28, (online).

65 The start-up fuel cost can be factored in either the heat rate, fuel cost or VOM cost component of the energy price limit calculation. The ERA has included it as part of the VOM cost as it has considered the start-up fuel cost as a cost per start. This is consistent with the approach adopted in determining the VOM cost for the Parkeston units in section 2.2.1. Any comparison between the VOM cost determined this year and historical VOM costs should consider that previous reviews did not include start-up fuel cost in the VOM cost.

Table 9. Estimate of VOM cost, Pinjar units

Item	Unit	Cost input	Notes
Maintenance costs	$/start	[redacted]	As explained above in this section.
Start-up fuel consumption	$/start	[redacted]	As explained above in this section.
Estimate of variable inputs such as water, labour and lubricants	$/MWh	[redacted]	Consistent with estimates in previous reviews escalated for inflation.
Average duration of dispatch per start (short dispatch)	Hours	[redacted]	Duration of short dispatch is sampled from a distribution. See details in Appendix 4.
Mean energy generated per start (short dispatch)	MWh/start	[redacted]	Energy generated over a short dispatch is sampled from a distribution. See details in Appendix 4.
Average capacity factor as a function of runtime (short dispatch)	%	[redacted]	Capacity factor is estimated based on sampled short dispatch duration. See details in Appendix 4.
Mean VOM cost	$/MWh	40.2	

Source: ERA analysis of Synergy data, 2021.

The WEM Rules require the ERA to review the method for setting the price limits at least once every five years.[66,67] Energy Policy WA is developing the detailed design for a new market power mitigation mechanism for the WEM, which covers the price limits. The new mechanism proposes the ERA to provide offer construction guidelines aiming to provide clarity on the types of costs that could be included in offers to the energy market.[68] Energy Policy WA's review and the ERA's guidelines can provide clarity on the calculation of costs to be included in the calculation of the price limits and offers to the market.

[66] Wholesale Electricity Market Rules, 1 October 2021, clause 2.26, (online).

[67] The ERA had commenced this method review in 2020 but suspended it due to its overlap with the State Government's Energy Transformation program. ERA, 2020, *Review of the methods used to calculate the benchmark reserve capacity price and energy price limits – Suspension of the method reviews*, (online).

[68] EPWA, 2020, *Proposal for changes to market power mitigation mechanisms*, consultation paper, p. 10, (online).

Appendix 3 Energy price limits based on 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.

Delivered gas price for the Pinjar units

The ERA determined a distribution for delivered gas prices for the Pinjar units after considering Synergy's expected contract gas price of [redacted] and Jacobs' forecast based on spot prices from the gasTrading platform, estimated at an average of $5.04/GJ (undelivered). The ERA also considered Jacobs' forecast of a distribution of gas transmission costs to the Pinjar units, which had an average of $1.574/GJ.

The resulting average of the distribution of the delivered gas price for the Pinjar units is $7.55/GJ, which is higher than the mean fuel cost of $7.03/GJ estimated in the 2020 review.

The ERA considered Synergy's expected gas contract cost of [redacted] which was provided confidentially to the ERA. Synergy's contract gas price [redacted] the expected price forecast by Jacobs. To minimise the risk of under-recovery of cost for generators, the ERA has assigned a higher weight to the gas price source that yields the highest price limits. This approach is consistent with the ERA's decision-making principles explained in section 2.

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.[69] To account for the uncertainty in transmission costs, the ERA's consultant assumed the minimum spot price for full haul on the DBNGP is normally distributed with a mean value of $1.574/GJ and a standard deviation of $0.15/GJ (refer to Appendix 8).

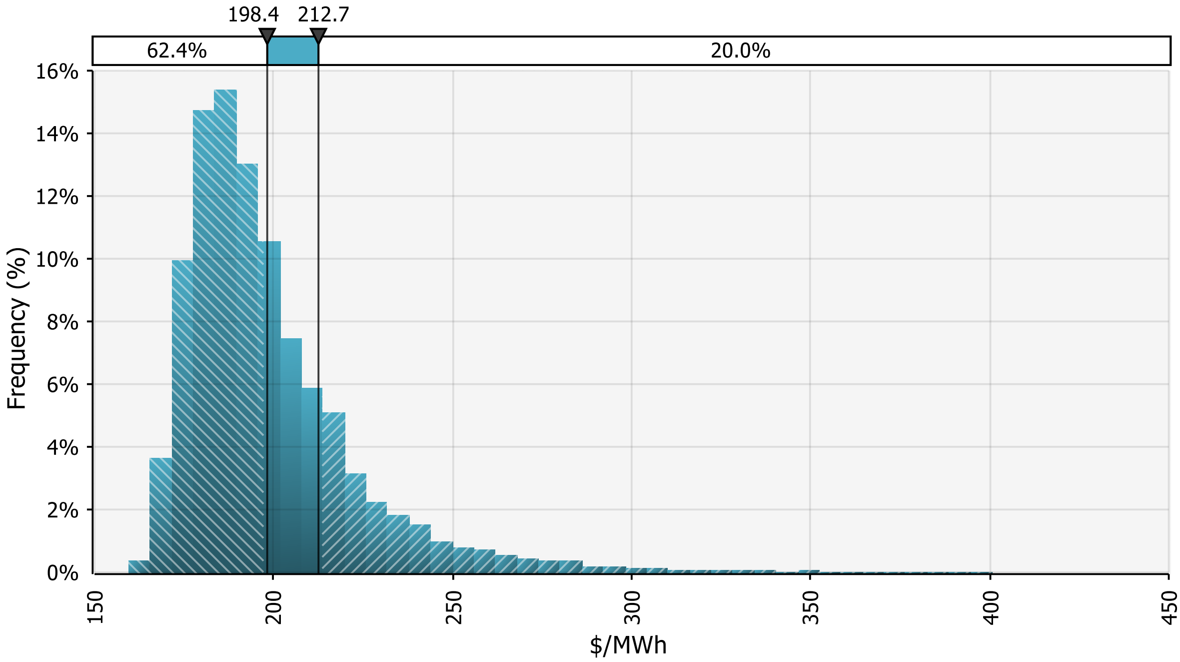
Maximum STEM price

Figure 12 shows the estimated distribution of the average variable cost for Pinjar. The Pinjar units are not the price setter in this year's review as the assessed maximum STEM price for Pinjar units is $213/MWh compared to $290/MWh assessed for the Parkeston units.

Table 10 outlines the changes in the underlying parameters of the energy price limits calculation as based on the Pinjar units.

[69] The ERA sets reference tariffs to assist in the negotiation process for reference services, which are the firm haulage services on the DBNGP and the Goldfields Gas Pipeline. The ERA recently revised the access arrangement for the DBNGP for the 2021-2025 period, (online).

Figure 12. Average variable cost distribution, Pinjar units



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

Table 10. Calculation of the maximum STEM price, Pinjar units

Component	Unit	Assessed value – 2021	2020 determination	Variance	Reason for variance
Mean variable O&M cost	$/MWh	40.2	110.5	(70.3)	Significantly lower maintenance and overhaul costs as provided by asset owner resulting in lower variable cost per start.
Mean heat rate at minimum capacity	GJ/MWh	21.5	19.2	2.4	Amended method for determining the distribution of minimum capacity results in the increase in the mean heat rate.
Mean fuel cost	$/GJ	7.6	7.0	0.6	Higher base gas price using a confidential weighted price based on forecast contract price as provided by asset owner and forecast spot price.
Loss factor	-	1.0229	1.0274	(0.005)	Determined by Western Power.
Mean of the average variable cost distribution	$/MWh	198	239	(40)	Risk margin varies with changes in the range of estimated distribution for average variable cost. The estimated distribution of average variable cost this year has a narrower range.
80th percentile of the average variable cost distribution	$/MWh	213	267	(54)	
Risk margin	%	7	12	(5)	Difference between the mean and 80th percentile value changes with changes in the range of possible values estimated.
Maximum STEM price	**$/MWh**	**213**	**267**	**(56)**	Resulting change in the underlying variables.

Note: Calculated values may differ due to rounding.

Alternative maximum STEM price

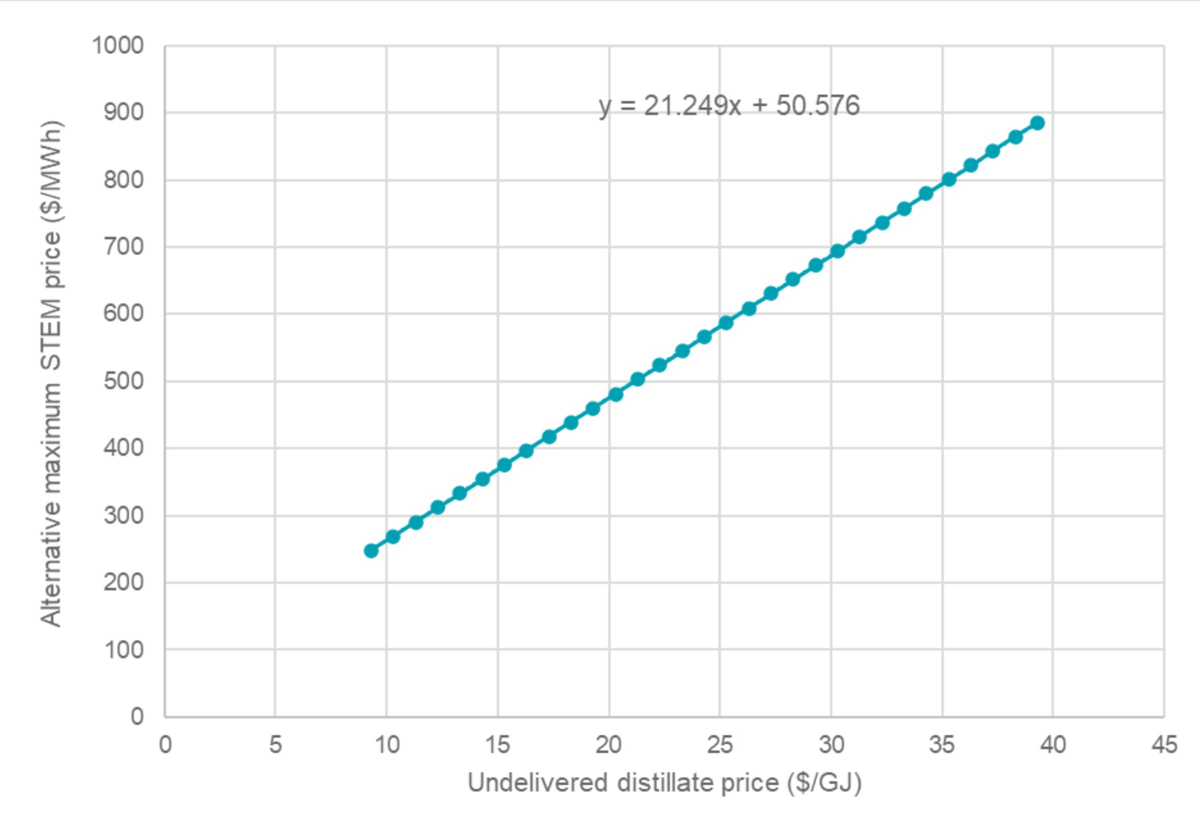
Based on the Pinjar units, the indexation formula for the alternative maximum STEM price is:

$$\begin{aligned} &\textit{alternative maximum STEM price} \\ &\qquad = 21.249 + (50.576 \times \textit{net ex–terminal distillate price}\ (\$/GJ)) \end{aligned}$$

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

Assuming a distillate price of $24.3/GJ, the alternative maximum STEM price is $567/MWh (Figure 13).

Figure 13. Proposed alternative maximum STEM price based on a sample of distillate prices, Pinjar units



Appendix 4 Operational characteristics of Pinjar and Parkeston units

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

Similar to 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 Synergy and 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 6 hours, d_i, expressed in hours.
- The sampled dispatch cycle capacity factor as a function of run time, $cf_i(d_i)$, expressed in 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 A4.1**):

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

The product of sampled maximum capacity, dispatch cycle duration and capacity factor yields 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.

Determination of operating parameters – Pinjar units

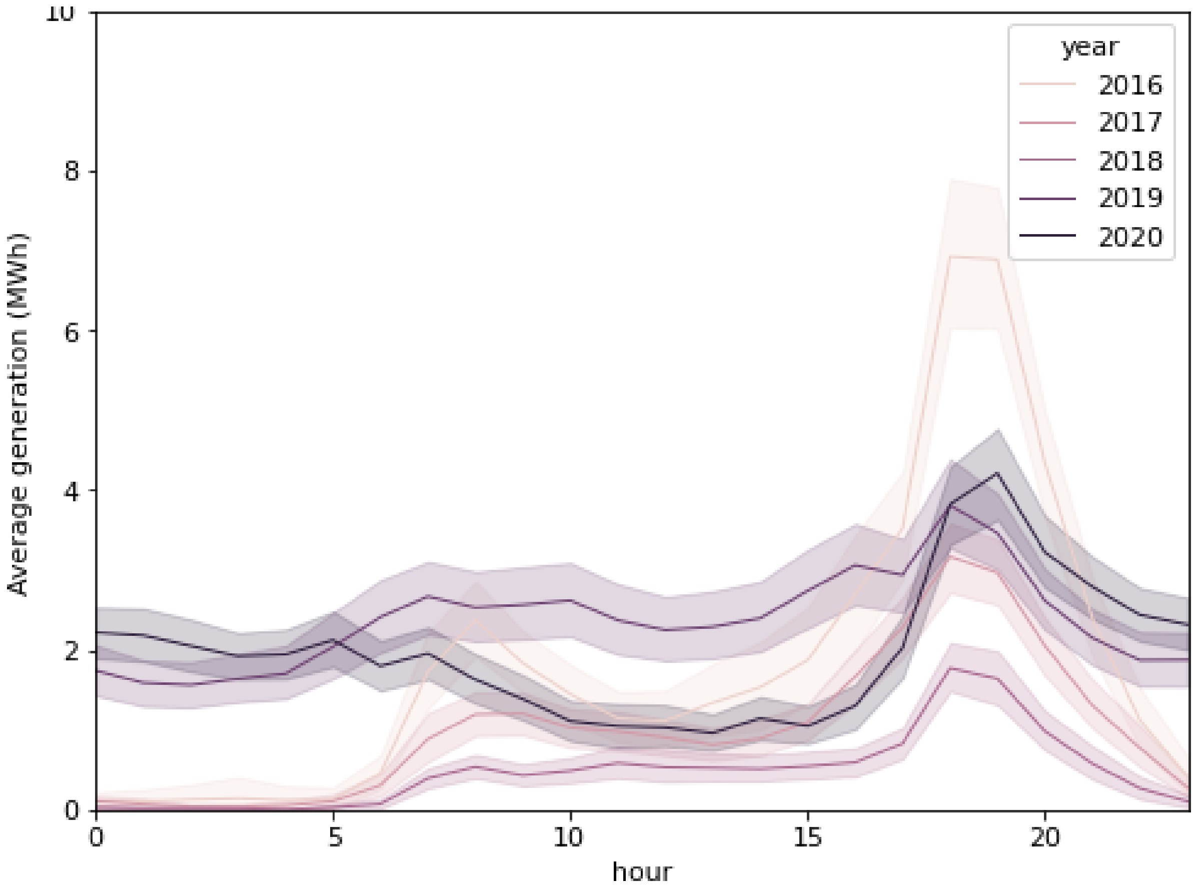
The analysis of dispatch cycle characteristics considered the observed dispatch of Pinjar units between 1 January 2016 and 31 December 2020. The following analysis is conducted to identify if the use of the whole 5-year observed dispatch data is appropriate for forecasting the future operation of the candidate machines.

The daily profile for the average output of Pinjar units is depicted in Figure 14. The chart shows an increase in the average output of these units during early morning hours in 2019 and 2020 when compared to those hours in prior years. After a decreasing trend since 2016, the output of the units has gradually increased during evening peak demand hours. In previous reviews of the energy price limits, AEMO's consultant (Jacobs) found that the average output of the Pinjar units generally declined after the commencement of the operation of High Efficiency Gas Turbines in September 2012.

Figure 14 shows the daily profile of the number of starts across Pinjar units. The units most frequently start during the evening peak demand hours. In 2020, the number of starts during peak demand hours increased above that observed in the prior three years. As shown in Figure 15, the number of starts during peak demand hours was more comparable to that occurred in 2016. For this reason, the ERA considered the entire five-year sample of number of starts to forecast the future dispatch cycle characteristics for these units. 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 in the past five years.

[redacted]

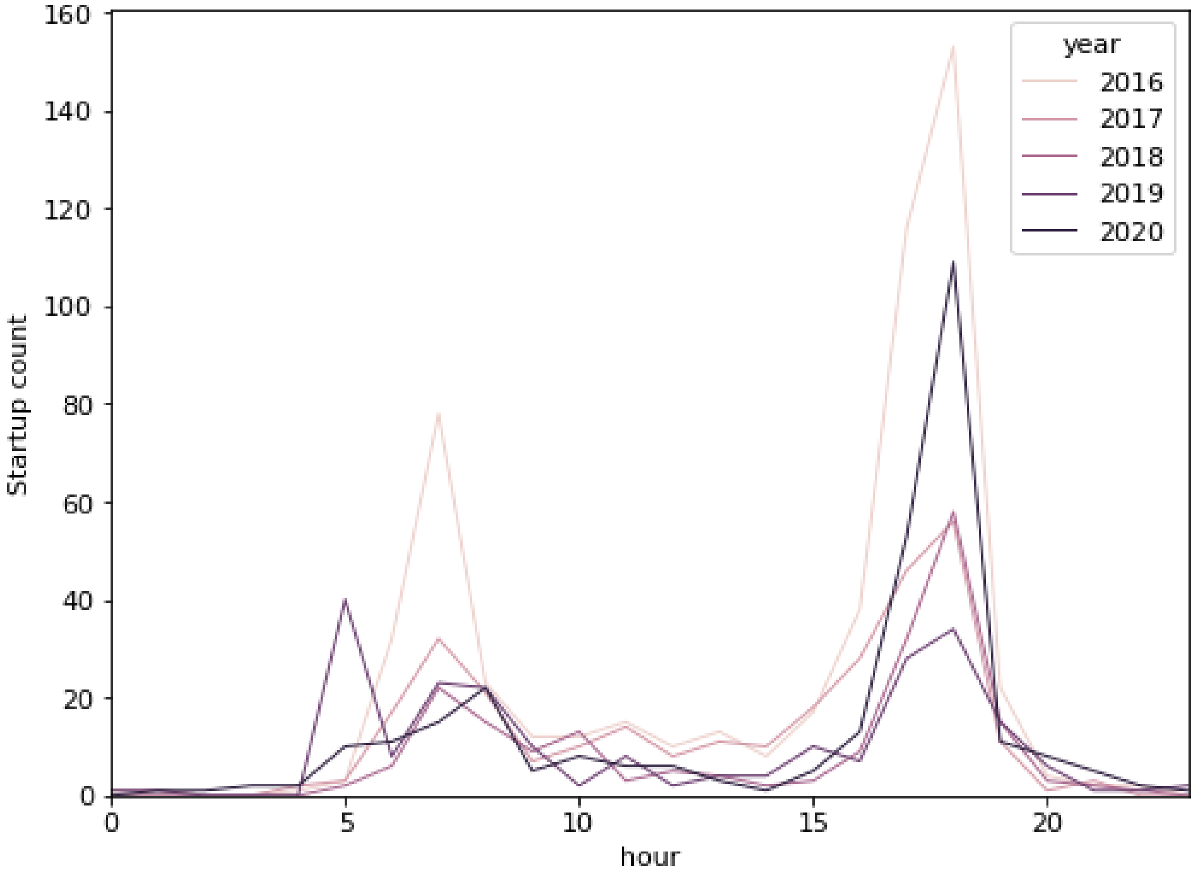
Figure 14. Average generation per hour of day, Pinjar units, 2016 to 2020



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

Note: shaded areas show the 95 per cent confidence interval for the average output.

Figure 15. Start-up count per hour of day, Pinjar units, 2016 to 2020



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

The analysis of the Pinjar units' dispatch cycles since 2016 show that:

- The average duration of dispatch cycles is approximately 5.6 hours.
- The average generation per dispatch cycle is approximately 84 MWh.

About 79 per cent of all dispatch cycles observed are dispatch cycles with a duration equal to or less than six hours – which in this report are referred to as short dispatch cycles. The observed dispatch contained dispatch cycles as short as 0.5 hours. The average duration of short dispatch cycles is approximately 2.9 hours. The average amount of energy generated per a short dispatch cycle is approximately 37 MWh.

The share of short dispatch cycles from all dispatch cycles is comparable to that observed between 2013 and 2016 (81 per cent).

For clarity, the entire distribution of the annual number of dispatch cycles (including cycles lasting more than six 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 converts the sampled annual number of actual starts to a sampled factored start. The sampled factored starts are then used to determine the timing of future maintenance cash flows, as explained in Appendix 2.

Number of starts per year

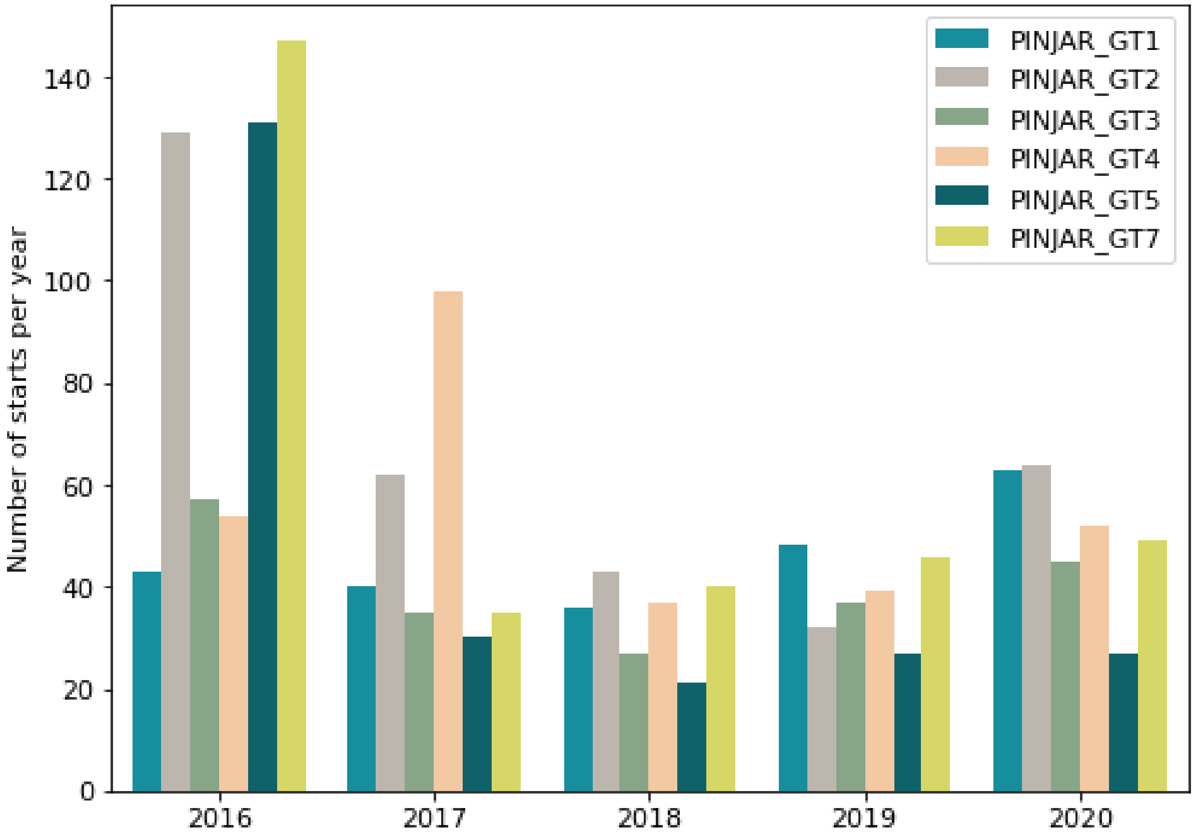
The ERA's modelling fits a normal distribution to the number of starts per year, n_s, using the above information. Based on the range of observed annual number of starts, the lower and upper bound of the distribution are set to 21 and 147 starts per year, respectively.

Figure 16 shows the number of starts per year for each Pinjar unit. Over the study period, the Pinjar units started between 21 and 147 times a year individually. Over the study period:

- on average they started 53.1 times per year.
- the standard deviation of number of starts per year was 31.8.

The ERA's modelling fits 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 are set to 21 and 147 starts per year, respectively.

Figure 16. Annual number of starts, Pinjar units, 2016 to 2020



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

In the 2019 and 2020 review of the price limits, AEMO's consultant (Marsden Jacobs) considered average 58 and 54 starts per year, respectively. For its simulation Marsden Jacobs fitted gamma distributions to the observed number of starts per year for these units.[70] In 2017 and 2018 review of the price limits, AEMO's consultant (Jacobs) considered an average of 68.5 and 64.9 starts per year, respectively. Jacobs assumed normal distributions for modelling the frequency of starts per year.

[70] Marsden Jacobs, 2020, *2020-21 Energy price limits review – final report (public)*, p. 30, (online).

Number of factored starts

The maintenance cycle described in Appendix 2 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. 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 thus 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.

In previous reviews of the price limits until 2018, AEMO's consultant (Jacobs) considered a 20 per cent uplift in the number of actual starts (i.e. a maintenance factor of 1.2) to account for the contribution of actual starts in peaking mode to the number of factored starts. Jacobs used this 20 per cent uplift to forecast future maintenance cash flows regardless of the maintenance type.

In 2018, Jacobs reconsidered this calculation of factored starts after receiving feedback from Perth Energy. Jacobs considered that for the Pinjar units, trips, fail-to-start restarts and low-load starts – starts with output less than 60 per cent of the maximum capacity – were the main factors influencing the ratio of factored starts to actual starts. In the absence of information from asset owners, Jacobs used a maintenance factor of 0.84, which was based on data available from comparable units in other power systems.[71]

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).[72] 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.

Over the past five years, 79 per cent of Pinjar starts were low-load starts. This is comparable to what Jacobs concluded for the period between 2013 to 2017. Given that a substantial number of Pinjar starts are low-load starts, it is expected the maintenance factor for types B and C to be smaller than one.

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

71 Jacobs, 2018, *Energy price limits for the Wholesale Electricity Market in Western Australia*, p. 29, (online). Jacobs assumed each actual start of the machine counts as 0.84 factored starts, which is the average of 0.5 ratio applicable to low-load starts and 1.2 ratio applicable to trips and fail-to-start restarts.

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

Maintenance factor for type A maintenance $MF_A = 1.07$

Maintenance factor for type B or C maintenance $MF_{B/C} = 0.680$

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

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

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

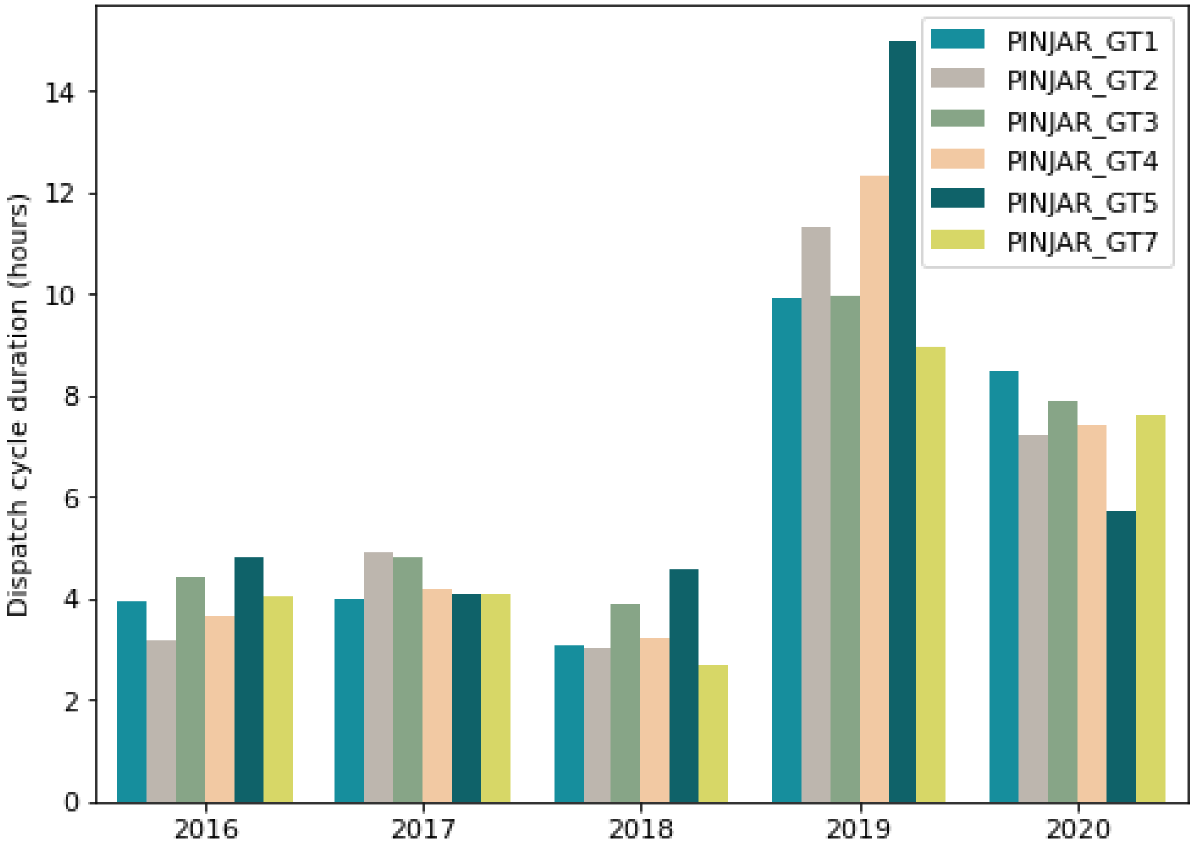
This provides for identifying the timing of future maintenance expenditures based on the number of factored starts per year in each simulation iteration i.

Dispatch cycle run time

The annual average dispatch cycle duration for the Pinjar units was between 2.7 and 15.0 hours, as shown in Figure 17. The average duration of dispatch cycles across 2016 to 2020 was approximately 6.1 hours. The relatively short dispatch cycle durations for these machines result in the number of starts to set the trigger points for running maintenance works.[73]

[73] As discussed in Appendix 2, the Pinjar turbines are due for maintenance every 600 factored starts or 12,000 factored hours operation, whichever becomes due first. When the average dispatch cycle duration is below 20 factored hours, the number of factored starts sets the trigger point for maintenance.

Figure 17. Annual average dispatch cycle duration, Pinjar units, 2016 to 2020



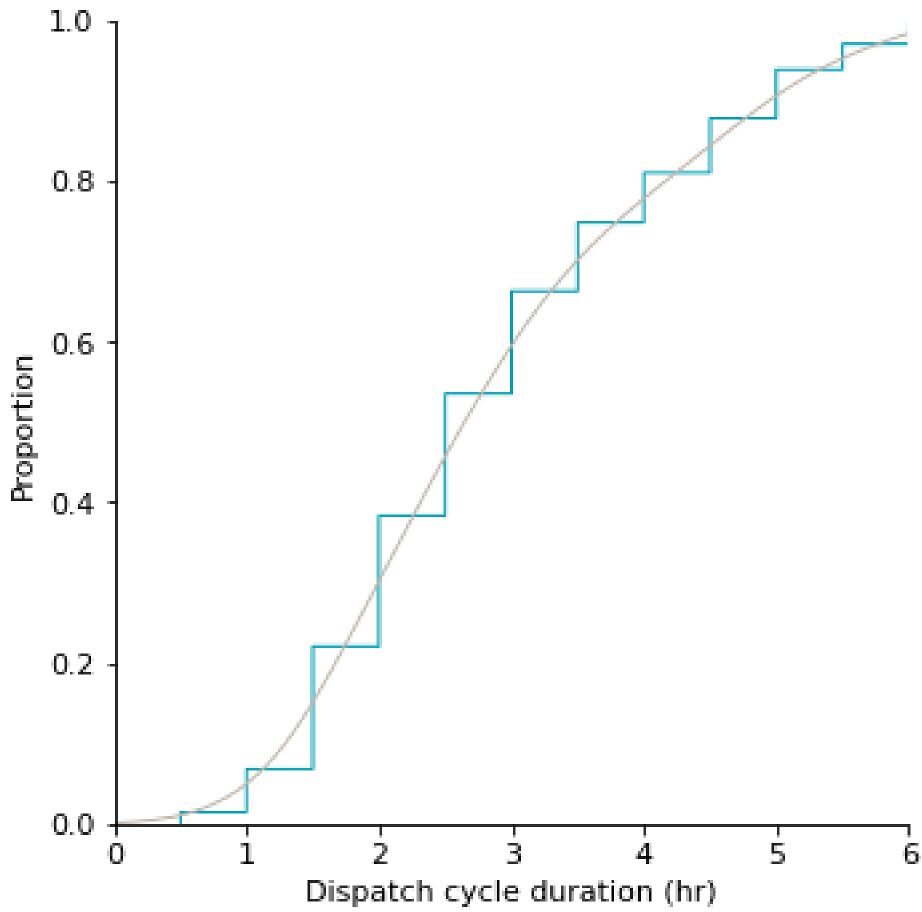
Source: ERA's analysis based on SCADA data published by AEMO

For the conversion of discounted variable O&M cost expressed in dollar per start to variable O&M cost expressed in dollar per MWh, the model samples from the distribution of short dispatch cycles between 0.5 and 6 hours. This ensures the estimated start-related variable O&M cost is amortised over relatively short dispatch run times and estimated short run marginal cost reflects high operating cost condition of the machines, as intended by the WEM Rules.

The model samples from the empirical distribution of short dispatch cycle duration, smoothed by a kernel-density estimate.[74] The empirical short dispatch cycle duration for Pinjar units is presented in Figure 18.

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

Figure 18. Empirical cumulative distribution of dispatch cycle duration for short dispatch cycles, Pinjar units, 2016 to 2020



Source: ERA's analysis using 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.

The average of short dispatch cycle duration is 2.9 hours. The lower and upper bound for this distribution are set to 0.5 and 6.0 hours.

For comparison, in the 2019 and 2020 review of the price limits, Marsden Jacobs reported an average of 2.75 and 3.6 hours of operation for each Pinjar short dispatch event, respectively.[75]

Maximum capacity

The maximum capacity of gas turbines varies with air temperature and humidity. An estimate of maximum capacity for candidate machines is needed to calculate the capacity factor of the units as per equation A4.1. In previous determination of the price limits, AEMO's consultant (Jacobs) derived the maximum capacity of the units from historical dispatch data having regard for the seasonal time of year. This was to account for variation in the maximum output of units when running the uncertainty analysis.[76]

[75] Marsden Jacobs, 2019, *2019-20 Energy Price Limits Review – Final Report (public)*, p. 30, (online) and Marsden Jacobs, 2020, *2020-21 Energy Price Limits Review – Final Report (public)*, p. 30, (online).

[76] Jacobs, 2018, *Energy Price Limits for the Wholesale Electricity Market in Western Australia – Final Report*, (online).

This paper uses a constant maximum capacity in the calculations. This is because accounting for seasonal variation in maximum capacity creates additional computational steps with no benefit. As explained in section 2.2.2, 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.

The model sets the maximum capacity of the units to the maximum value observed over the past five years.

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 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. In previous determinations of the price limits, AEMO's consultant reviewed the historical output level of the candidate machines to infer a distribution for the minimum capacity of the units as observed in practice.[77] The ERA adopted a similar approach to that conducted in the previous reviews, as explained below, and makes amendments to improve it.

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 19 shows the cumulative empirical distribution of the output level of Pinjar units observed between 2016 and 2020.

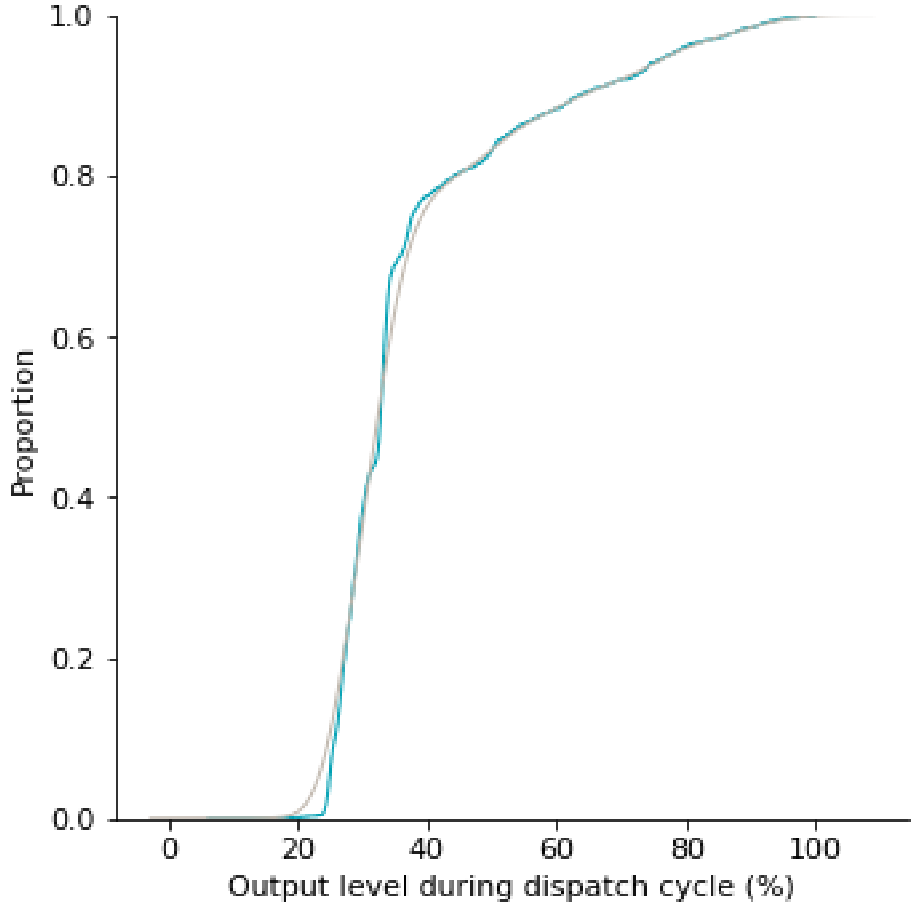
The data used in the analysis is recorded in half-hourly format. This makes the estimate of the output level of the machines during the first and last trading interval in each dispatch cycle unreliable. This is because it is not known over what period of time the recorded energy was generated. To address this issue, previous analyses of the minimum capacity of these machines assumed a uniform distribution for the actual duration of the first and last trading intervals having consideration for the ramp up and ramp down rates for these units.[78] The ERA did not adopt the same approach in its modelling as it would not provide any additional computation benefit. The ERA's analysis instead 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.[79]

[77] Ibid, p.16.

[78] This was provided in a confidential appendix to the ERA as part of the review of the price limits in previous years.

[79] 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 19. Empirical cumulative distribution of output level (capacity factor) reached during short dispatch cycles, Pinjar units, 2016 to 2020



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

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

As shown in Figure 19, the minimum capacity of the units observed is approximately 18 per cent of the maximum capacity. The probability of observing output levels below 18 per cent is negligible. Half of the observed dispatch levels are below 33 per cent loading.

Previous reviews of the price limits by Jacobs, AEMO's consultant, fitted a normal distribution to the lower half of this empirical distribution to infer a distribution for minimum capacity. The lower half of the above distribution has a mean of 28.1 per cent and standard deviation of 2.6 per cent. The mean of this distribution yields an expected minimum capacity that is close to the minimum stable generation limit of Pinjar.

Previous reviews of the price limits used the same approach above to infer a distribution for minimum capacity for Parkeston. However, as explained in the next section, the inferred distribution mean was substantially larger than the minimum stable generation limit for Parkeston. This resulted in estimating a lower fuel cost for Parkeston than expected cost during operation around minimum stable generation for these units. To address this matter, the ERA's analysis used the first 10 percentiles of the empirical distribution of output levels for the candidate units.

Based on the first 10 percentiles of the empirical distribution of output level for Pinjar, the minimum output level is modelled as a normal distribution with mean of 24.7 per cent of maximum capacity and standard deviation of 1.39 per cent of maximum capacity. The lower and upper bounds of the distribution are set to 18.0 and 27.2 per cent of maximum capacity.

For comparison, in 2018, AEMO's consultant used a normal distribution for the minimum capacity of Pinjar with a mean of [redacted] per cent and a standard deviation of [redacted] per cent.[80] At the time, Jacobs found half of Pinjar outputs during dispatch cycles were below [redacted] per cent of its maximum capacity. Jacobs also found the minimum output of the plant was around [redacted] per cent of the maximum capacity of the units.

The average of the resulting distribution of the Pinjar units' minimum capacity is 10.1 MW, which is comparable to the minimum stable generation level of [redacted] MW.

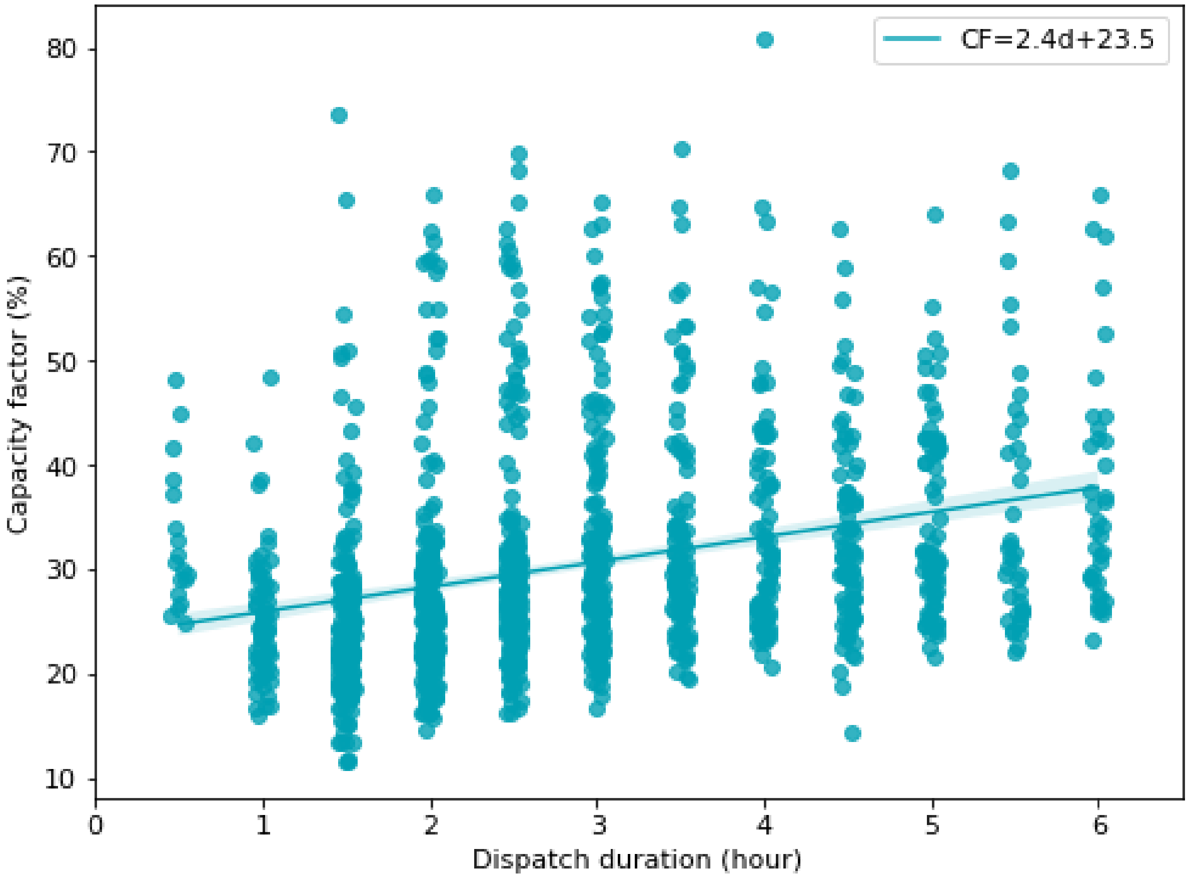
Relation between capacity factor and run time

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 Pinjar. Figure 20 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.

80 Ibid.

Figure 20. Relationship between dispatch cycle duration and capacity factor, Pinjar units, 2016 to 2020



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

Determination of operating parameters – Parkeston units

This paper used the estimate of VOM costs for the Parkeston units as provided by the asset operator. Therefore, a bottom-up calculation of VOM costs was not needed for the Parkeston units. Nevertheless, a review of operating characteristics for Parkeston is needed to convert VOM costs that were provided as cost per start figures to cost per unit of energy generated. The conversion method is identical to that used for Pinjar, as explained in the previous section.

The analysis of dispatch cycle characteristics considered the observed dispatch of Parkston units between 1 January 2018 and 30 July 2020 and information received from the operator of these units. This choice of historical data was based on information received from the asset operator that considered the past three years better reflect the future operation of these units.

The following analysis is conducted to identify if the use of the whole available observed dispatch data is appropriate for forecasting the future operation of the machines.

The daily profile for the average output of Parkston units is depicted in Figure 21. The chart shows [redacted] the average output of these units across all hours in 2020 and the first half of 2021 when compared to those in prior years. One of the Parkeston units generally is in operation to serve an embedded mining load.

Figure 21. [redacted]

[redacted]

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

Note: shaded areas show the 95 per cent confidence interval for the average output.

As shown in Figure 21, the units most frequently start during early hours in the morning followed by evening peak demand hours. In 2020, the number of starts during early hours in the morning [redacted] that observed in the prior two years.[81] The number of starts during peak demand hours, however, is comparable across observed years.

All three units frequently stop operating during low demand periods in the SWIS when the balancing price is typically low. [redacted] Any excess energy generated is exported to the SWIS. Given the existence of the embedded load, the operation profile of individual Parkeston units can substantially differ from each other. This is discussed in more detail in the following sections.

[81] The 2021 sample does not cover a complete year and hence is not a reliable indicator of the number of starts for a whole year.

Figure 22. [redacted]

[redacted]

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

The ERA's analysis considered the entire sample of observed dispatch since 2018 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 2018. This decision was also informed by information provided by Goldfields Power.

[redacted]

A possible decrease in the utilisation of the units can decrease the estimate of VOM costs for these units.

The analysis of Parkeston dispatch cycles since 2018 shows that:

- The average duration of dispatch cycles is approximately [redacted]. This is [redacted] the corresponding value for Pinjar.
- The average generation per dispatch cycle is approximately [redacted]. This is [redacted] the corresponding value for Pinjar.

- About [redacted] of all dispatch cycles observed are short dispatch cycles. This is [redacted] than the corresponding ratio for Pinjar units. The observed dispatch contained dispatch cycles as short as 0.5 hours. The average duration of short dispatch cycles is approximately [redacted] The average amount of energy generated per a short dispatch cycle is approximately [redacted].

Frequency of starts per year

Figure 23 shows the number of starts per year, n_s, for each Parkeston unit. Overall, units G01 and G03 had more comparable operating profile to each other. Unit G02 had substantially fewer starts over the study period.

Over the study period, units G01 and G03 started between [redacted] times a year individually:

- On average they started [redacted] per year.
- The standard deviation of number of starts per year was [redacted].[82]
- Unit G02 started between [redacted] times over the study period. The unit on average started [redacted] times a year with a standard deviation of [redacted] times per year. [redacted]

[82] These estimates exclude the 2021 period because data for this period only covers the first six months of the year.

Figure 23. [redacted]

[redacted]

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

Note: data for 2021 only covers the first six-month period of the year.

Dispatch cycle run time

The annual average dispatch cycle duration for Parkeston units G01 and G03 was between [redacted] [redacted].[83] Figure 24 shows the changes in the annual average dispatch cycle duration over the study period. Table 11 summarises the mean and standard deviation of annual average dispatch cycle duration and energy generated for each unit separately.

In 2019, unit G02 started [redacted] times only, for which the dispatch cycle average duration was substantially larger ([redacted] hours) than other dispatch cycles across other units and other years. This contributes to the large variation in the dispatch cycle energy generated for this unit.

83 As discussed in Appendix 2, the Pinjar units are due for maintenance every 600 factored starts or 12,000 factored operation hours, whichever becomes due first. When the average dispatch cycle duration of the units is below 20 hours, the number of factored starts sets the trigger point for maintenance.

Figure 24. [redacted]

[redacted]

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

Table 11. Annual average dispatch cycle duration and energy generated for the entire dispatch cycles observed, Parkeston units

Item	Unit	Measure	G01	G02	G03
Annual dispatch cycle duration	Hours	Average	[redacted]	[redacted]	[redacted]
		Standard deviation	[redacted]	[redacted]	[redacted]
Annual dispatch cycle energy generated	MWh	Average	[redacted]	[redacted]	[redacted]
		Standard deviation	[redacted]	[redacted]	[redacted]
Annual average dispatch cycle capacity factor	%	Average	[redacted]	[redacted]	[redacted]

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

Despite substantial differences between the operation profile of the units, their average capacity factors during dispatch cycles were comparable – varying between [redacted].

For the conversion of VOM costs expressed in dollar per start to VOM costs expressed in dollar per MWh, the model samples from the distribution of duration for short dispatch cycles between 0.5 and 6 hours. This ensures the estimated start-related VOM cost is spread over relatively short dispatch run times and the estimated cost reflects high cost operating condition of the machines.

The model samples from the empirical distribution of short dispatch cycle duration, smoothed by a kernel-density estimate.[84] The empirical short dispatch cycle duration for Parkeston units is presented in Figure 25.

Figure 25. [redacted]

[redacted]

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.

The average of short dispatch cycle duration is 3.2 hours. The lower and upper bound for this distribution are set to 0.5 and 6.0 hours.

Maximum capacity

Consistent with the approach adopted for the analysis of the Pinjar units, this review uses a constant maximum capacity in the calculations for the Parkeston units. This is 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

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

the empirical distribution of dispatch duration and capacity factor. Any variation in maximum capacity is already captured in the empirical distributions used.

The model sets the maximum capacity of the units to the maximum value observed over the study period.

Minimum capacity

The analysis conducted to determine the distribution of minimum capacity of the Parkeston units is identical to the approach used for the Pinjar units, as explained in the previous section. The analysis considered the observed output level of Parkeston during short dispatch cycles as a percentage of the maximum capacity of the units. Figure 26 shows the cumulative empirical distribution of the output level of Parkeston units observed between 2018 and 2021.

Figure 26. [redacted]

[redacted]

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

As shown in Figure 26, the minimum capacity of the units observed is approximately [redacted] per cent of the maximum capacity. The probability of observing output levels below [redacted] per cent is negligible. Half of the observed dispatch levels are below [redacted] per cent.

The lower half of this empirical distribution has a mean of [redacted] per cent of maximum capacity (approximately [redacted]) and standard deviation of [redacted] per cent of maximum capacity. The ERA's analysis initially considered following the practice in previous reviews of the price limits and use these figures to infer a distribution for minimum capacity. However, the mean of the minimum distribution inferred is substantially larger than minimum stable generation limit for Parkeston units. Use of heat rate at such level of capacity under-estimates the fuel cost for Parkeston when it operates close to minimum stable generation limit.

All of the heat rates used in recent reviews of the price limits used smaller heat rates for Parkeston units than their heat rate at minimum generation level for these units, which is at [redacted]. For clarity, use of lower heat rate results in lower estimates for fuel cost.

For comparison, in 2018, AEMO's consultant assumed a normal distribution for the minimum capacity of Parkeston with a mean of [redacted] per cent of maximum capacity (approximately [redacted]) and a standard deviation of [redacted] per cent of maximum capacity. For the 2017 review, Jacobs used a normal distribution with a mean of [redacted] per cent of maximum capacity (approximately [redacted]) and standard deviation of [redacted] per cent of maximum capacity.[85] In the 2019 and 2020 review of the price limits Marsden Jacobs reported the average heat rate at minimum capacity for Parkeston. The reported heat rates are associated with heat rate at [redacted] output levels for these plants, which both are substantially larger than the minimum stable generation output for these units.

This paper 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 21.01 per cent of maximum capacity and standard deviation of 8.61 per cent of maximum capacity. The lower and upper bound for this distribution is set to 2.71 and 47.8 per cent of maximum capacity, respectively.

Relation between capacity factor and run time

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 27 depicts the expected capacity factor over a dispatch cycle as a function of dispatch cycle duration, derived from the historical dispatch of the units.

Consistent with the approach adopted for the Pinjar units, the model uses the linear line fitted to the historical data to determine the expected capacity factor subject to the sampled run time 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.

85 This was provided in a confidential appendix to the ERA as part of the review of the price limits in previous years until 2018.

Figure 27. [redacted]

[redacted]

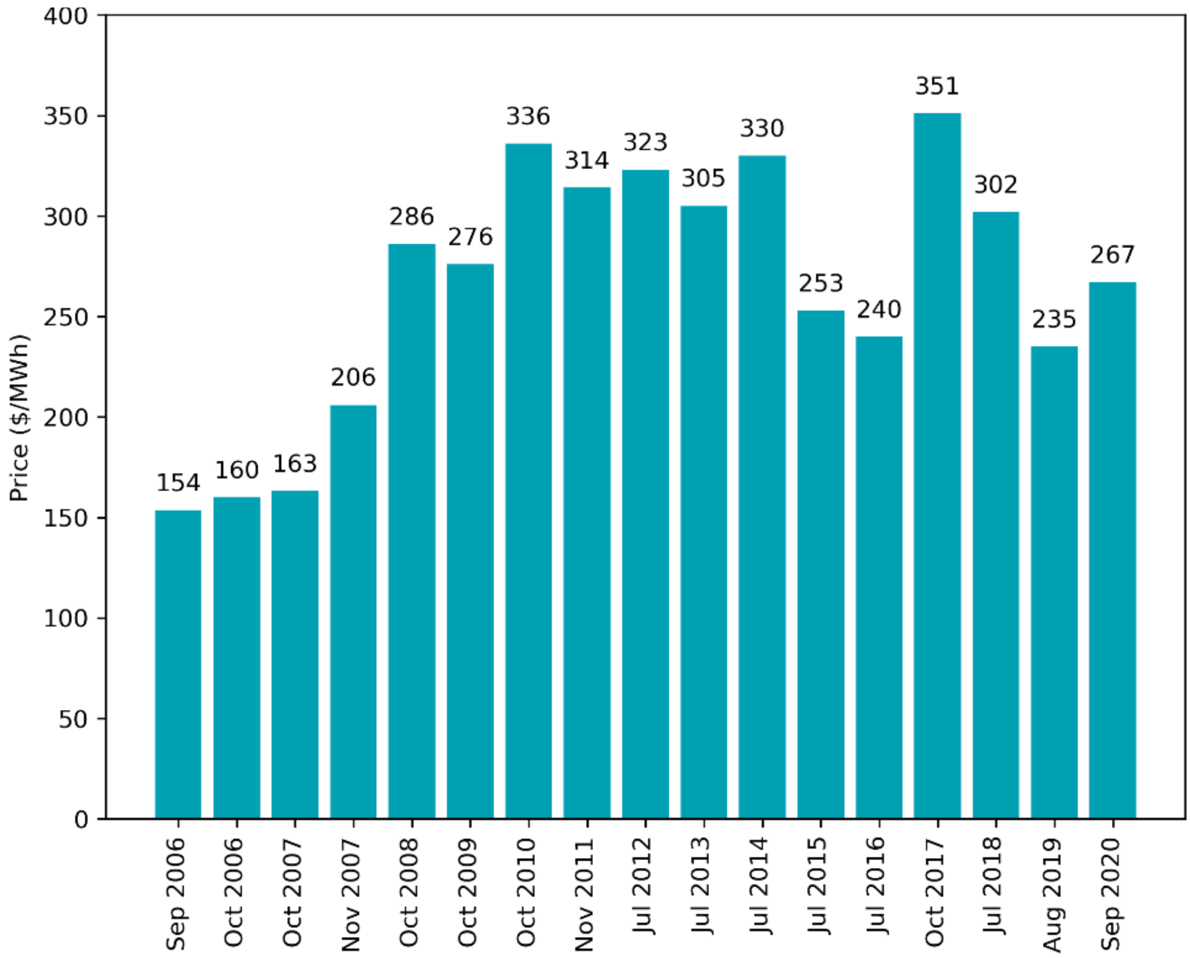
Source: ERA's analysis based on SCADA data provided by Goldfields Power.

Appendix 5 Historical price limits and market prices

This appendix presents historical energy price limits.

Figure 28 and Figure 29 depict the historical maximum STEM price and alternative maximum STEM price since the market commenced.

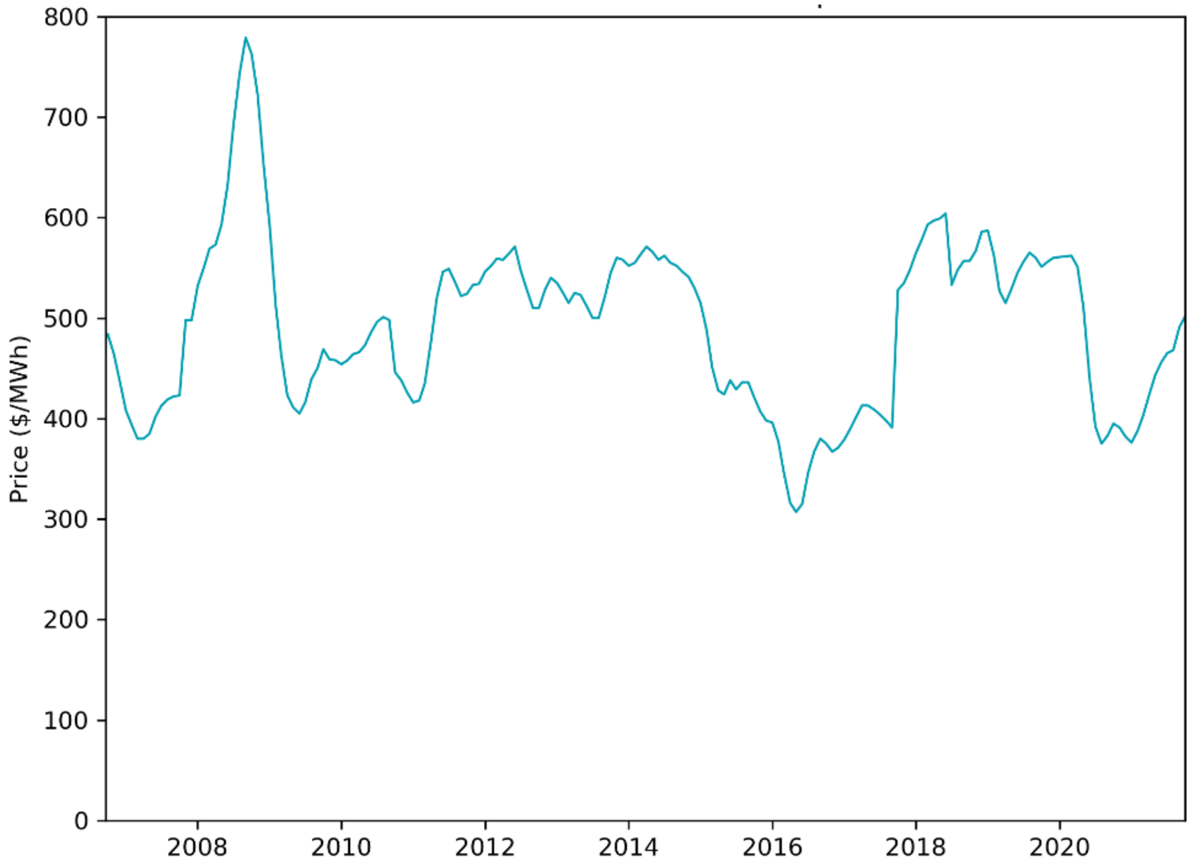
Figure 28. Historical maximum STEM price



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

Note: Dates show the month in which the price cap took effect.

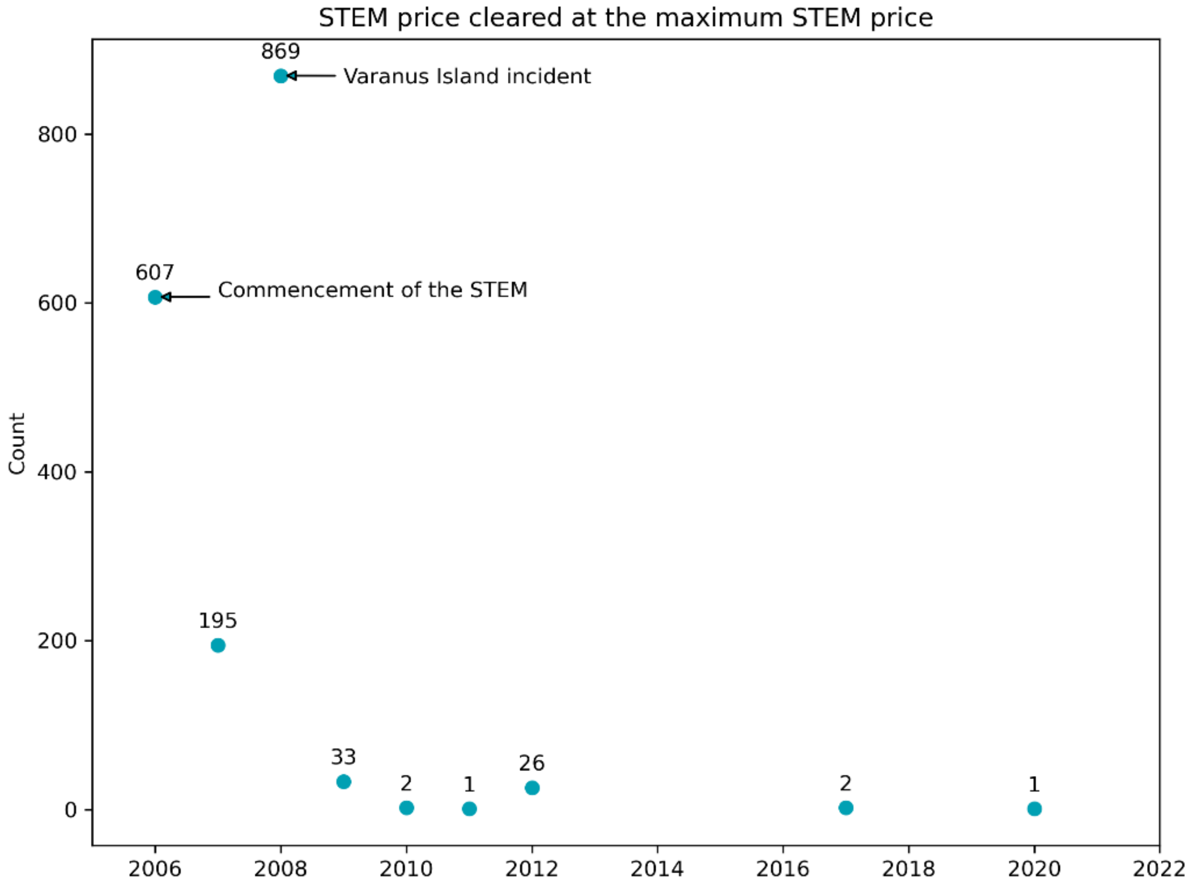
Figure 29. Historical alternative maximum STEM price



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

In recent years the STEM has seldom cleared at the alternative maximum STEM price. Figure 30 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 30: 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 2021 is based on information available as of October 2021.

Appendix 6 List of Figures

Appendix 7 List of Tables

Appendix 8 Jacobs' final report

Gas price forecast

Final draft report

August 26, 2021

Economic Regulation Authority

Gas price forecast

Project No:	Project Number
Document Title:	Draft report
Document No.:	Document No.
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Client Name:	Economic Regulation Authority
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Document history and status

Revision	Date	Description	Author	Checked	Reviewed	Approved
A	5-08-21	Initial draft report	PN			
B	25-08-21	Incorporated ERA's comments	PN			
C	26-08-21	Includes Jacobs internal review	PN	WG	WG	WG

Contents

Important note about your report

The sole purpose of this report and the associated services performed by Jacobs is for forecasting gas prices for the ***Economic Regulation Authority*** *(the Client) suitable to be used in the next Energy Price Limits review in accordance with the scope of services and terms and conditions set out in the contract between Jacobs and the Client.*

In preparing this report, Jacobs has relied upon, and presumed accurate, information (or confirmation of the absence thereof) provided by the Client and/or from other sources. Except as otherwise stated in the report, Jacobs has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

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1. Introduction

1.1 Overview

From 1 July 2021, the Economic Regulation Authority (ERA) is required to determine the Energy Price Limits (EPLs) that will apply to the Wholesale Electricity Market (WEM). The EPLs comprise:

- Maximum STEM price – applied in all trading intervals except when distillate-fired generation is required.
- Alternative maximum STEM price – applied in trading intervals when distillate-fired generation is required.

The EPL values are based on the ERA's estimate of the short-run marginal cost of the highest cost generation facility in the South West Interconnected System (SWIS) according to the formula:

Equation 1: Dispatch cost formula to determine Energy Price Limits for the WEM

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

The ERA requires a consultant to provide a gas price forecast that will inform the ERA's estimate of the "Fuel Cost" component of the above formula.

1.2 Scope of work

Economic Regulation Authority have engaged Jacobs to provide a gas price forecast that will inform the ERA on its estimate of the "Fuel cost" input in Equation 1, which is used to determine the Energy Price Limits in Western Australia's WEM. Fuel cost in Equation 1 is understood to be the average unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station, expressed in $/GJ.

The ERA notes that two methodologies have been used in the past to determine the "Fuel cost" input:

- Projecting the monthly maximum spot prices from the *gasTrading Australia* website using a standard ARIMA[1] time series model.
- Projecting the average quarterly natural gas price in Western Australia available from Department of Mines, Industry, Regulation and Safety (DMIRS) using a standard ARIMA time series model.

The ERA notes that both methodologies have advantages and disadvantages with respect to their use in the gas price forecast in the context of the EPL review. Jacobs was engaged by ERA to provide its own forecast of gas prices.

We were also asked to provide:

- The price at the gas producer's plant gate.
- The cost of transmission from the plant gate to the delivery points at Pinjar and Parkeston Power Stations. Parkeston transmission costs are to use both covered and uncovered capacity tariffs.

[1] Auto Regressive Integrated Moving Average

We were also requested to consider the effects of factors that can alter future gas prices. Examples include new projects, change in operation of gas storage plants, economic and operational impact of the COVID pandemic, and changes in domestic gas policy.

1.3 Conventions

Unless otherwise stated, all prices in this report are stated in real June 2021 dollars.

2. Gas Market Review

Jacobs has conducted a high-level review of Western Australia's (WA's) gas market as part of the backdrop for its gas price projection. The main source of the review was the Australian Energy Market Operator's (AEMO's) 2020 Western Australia Gas Statement of Opportunities (WA GSOO) document. The WA GSOO focuses on the supply/demand balance in WA's domestic gas market over the coming decade. In contrast, our price projection is focused over the coming 12-month period and the review was conducted accordingly.

The items covered in the review include:

- Overview of WA gas market.
- Impact of COVID.
- Supply side developments.
- Demand side developments and expectations.
- Gas storage.

2.1 Overview

The WA gas market is characterized by large gas fields that are mostly offshore, and primarily supply the global LNG market. There are a relatively small number of producer/suppliers and large consumers. WA's domestic gas market is expected to account for 9.8% of the state's total gas use. However, it is the largest gas market relative to the other Australian States and Territories with power generation, mining and mineral processing accounting for most of the gas usage (about 96% in total). In contrast only 2% of WA's gas usage is for residential and commercial customers.

The gas market has traditionally been dominated by confidential longer-term bilateral contracts, with 84% of gas consumed by large users. Short-term contracting and spot sales are small in volume but expected to increase as more consumers seek shorter term supply arrangements. The market has a small number of pipelines with limited spare pipeline capacity and it has also expanded its storage capacity to 78 PJ, via the 60 PJ Tubridgi storage facility, which was commissioned in late 2017. Total storage withdraw capability is 210 TJ/day, which represents about 20% of WA's average daily consumption, and the 78 PJ of storage capacity represents 20% of projected domestic gas consumption for 2021.

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

Shorter-term trades arise when parties want to vary their offtake volumes above maxima or below minima or avoid penalty payments. This can be done through over-the-counter trades or through exchanges, of which there are currently three third party exchanges[2]:

- The Inlet Trading market operated by DBNGP at the inlet to the pipeline, which enables pipeline shippers to trade equal quantities of imbalances.

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

- The gasTrading platform, which enables prospective buyers and sellers to make offers to purchase and bids to sell gas on a month-ahead basis at any gas injection point. The platform matches offers and bids and the gas is then scheduled, with subsequent daily adjustments. The market does not settle at a single daily price but a range of prices reflecting a series of bilateral transactions.

  The gasTrading website contains a time series of historical monthly prices and volumes. In past EPL reviews this has been used as a source for WA gas pricing with the acknowledgement that traded volumes only represented about 2% of the WA market.
- The gas trading platform operated by Energy Access Services since 2010. Energy Access has nine foundational members but usage of the platform is unknown.

The reasons parties may choose to participate in the above alternatives may include preferences to deal directly with counterparties, their scale of trading, preferred periods of trades (e.g. daily, monthly). There is anecdotal evidence that the bulk of spot trading is completed bilaterally via master spot agreements, but there is no publicly available data available to confirm this.

In its 2020 WA GSOO, AEMO acknowledges that the WA gas market is opaque, noting that information about uncontracted volume on both the supply and demand side is not available, and similarly contract pricing is also not generally known, other than in the aggregate. This is somewhat in contrast to the gas market on the east coast where gas is traded more actively and in greater volumes through short-term trading hubs.

2.2 Factors influencing the market outlook

2.2.1 Overview

In its 2020 WA GSOO, AEMO has found that the domestic gas market is expected to be well-supplied until 2026, under its Base scenario assumptions. Even under the Low scenario, where no new gas supply is assumed to be commissioned, there is still ample supply until 2025. In addition, gas storage in WA was filled to 85% capacity in November 2020 according to AEMO. Actual flows from the Mondarra and Tubridgi storage facilities since November imply current levels are at 57 PJ, which represents 73% of total storage capacity. We would expect spot gas prices to have low levels of volatility with the storage facilities being relatively full. There may also be an impact on contract prices with one to two years' duration given the size of storage relative to the domestic market.

2.2.2 COVID impacts

The main impacts of the COVID-19 pandemic have been assessed by the WA GSOO as follows:

- It has led to an increase in demand for commodities produced by WA such as gold (driven by investor demand). This in turn is expected to result in an increase in gas demand driven by increased mining activity that is projected to remain at elevated levels until 2022.

- Gas demand for iron ore mining is also expected to increase over the next five years due to mine closures in other parts of the world resulting from various issues, including COVID-19 impacts.

- It has resulted in delays of large LNG projects because the pandemic has reduced global LNG demand in an already oversupplied market putting downward pressure on prices. Projects are assumed to have been deferred from 2024 into 2027, and from 2026 to beyond 2030.

Effects of COVID-19 on consumption patterns were also investigated, including increased residential demand as more people work from home. However, the impact on gas demand was found to be negligible.

In summary, COVID-19 has moderately bolstered gas demand over the short term, which should provide price support for both contracted and spot gas over the next 12 months.

2.2.3 Supply side

We have noted above the expected delays to large LNG projects due to the oversupplied global market and accompanying weak oil and LNG prices. In contrast, a number of domestic-only projects have progressed in their development, with West Erregulla expected to be available from 2022 with increased production capacity and Beharra Springs Deep also expected to come online in 2021. These projects are not expected to increase overall domestic gas capacity but will maintain gas supply from existing projects, which tend to lose production efficacy over time.

Overall, potential gas supply in the short term is adequate relative to demand. AEMO has assessed potential gas supply for the domestic market in 2021 at 1,334 TJ/day and this increases to 1,418 TJ/day in 2022 for the Base scenario.

2.2.4 Demand

Domestic gas demand faces headwinds in some sectors and tailwinds in others. COVID-19 has had an overall positive impact on domestic gas demand with increasing demand for commodities such as gold, iron ore, nickel and mineral sands, at least in the short term. In the gas for power generation sector, gas demand is set to decline slightly in the short term as gas-fired generation in the WEM is displaced by new large-scale renewable generation capacity.

Overall gas demand in 2021 reduces from about 1,100 TJ/day in 2020 to 1,068 TJ/day under the Base scenario and is then expected to increase to 1,080 TJ/day.

2.3 Evaluation

Our high-level review suggests that for the 12-month outlook period that is relevant for our purpose there do not appear to be any apparent price shocks, or significant changes in market fundamentals, that may impact spot or contract gas pricing over this time. The COVID-19 pandemic, which may have contained in it the potential for such an impact, is expected to have a relatively mild influence on pricing. Its net impact appears to be that of price support as it has caused an increase in demand for WA’s commodities.

The bigger picture is that the WA domestic gas market is expected to be well-supplied until 2026 with potential for supply shortfall in 2029. There have been some changes to the outlook relative to the 2019 WA GSOO, in that enough supply was previously forecast to be available to meet demand until 2029. However, in our view these changes do not have any particular bearing on the 12-month outlook. Our conclusion is that time-series modelling for gas pricing over the next 12 months does not need to take into account any exogenous factors that have the potential to influence gas market pricing outcomes.

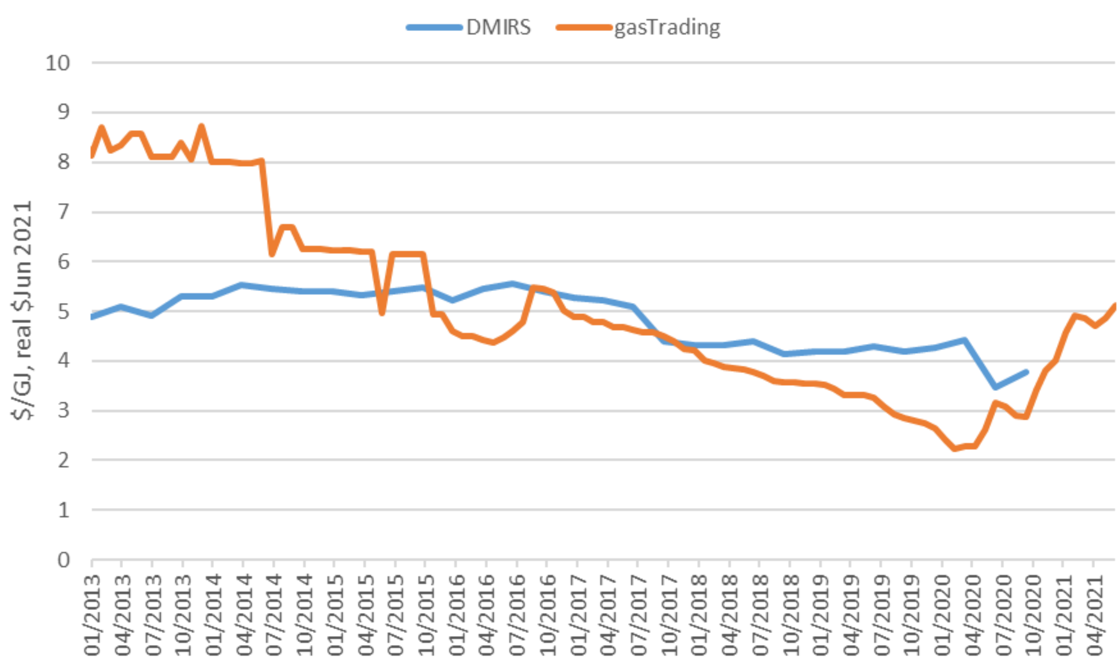
3. Gas Price Forecast

In more recent EPL reviews time series analysis has been used to forecast gas prices over the 12-month period in which the new EPLs would apply. Two sources of data have been used as the basis of the time series forecasting:

- Maximum monthly spot gas prices from the gasTrading website service[3].
- Average quarterly natural gas price supplied by the Department of Mines, Industry, Regulation and Safety (DMIRS).

Both time series are presented in Figure 1 from the beginning of 2013 until the latest available data, which is Q4 2020 for the DMIRS data and July 2021 for the gasTrading data. There is more variability in the gasTrading time series, which represents maximum monthly spot prices. The curious feature of the chart is that the maximum monthly spot price from gasTrading drops below the DMIRS average contract price from January 2018 and never exceeds it again, at least until Q4 2020.

Figure 1: DMIRS average quarterly and gasTrading maximum monthly time series



In the 2020-21 EPL review the feedback from some stakeholders was that spot prices were not representative of the true fuel costs faced by generators. Supply arrangements under the gasTrading exchange are understood to be predominately interruptible in nature, whereas the DMIRS price series represents the volume weighted average of gas sales by producers and is understood to be largely influenced by bilateral contracts, at least some of which would be for firm gas supply. As a result, the DMIRS time series was used as the basis of the previous EPL. However, in its final decision the ERA noted that the Market Rules do not require generators to hold firm gas contracts. By implication, firmness of gas supply is not the determining factor in deciding which time series is the most appropriate for gas price forecasting for the purpose of setting EPLs.

[3] http://www.gastrading.com.au/spot-market/historical-prices-and-volume

DMIRS time series

Prices under the DMIRS time series are predominantly based on bilateral contracts, some of which are with gas generators under firm supply arrangements. However, there are some drawbacks in the use of this time series for the purpose of determining EPLs:

- The bilateral contracts are forward looking in nature and have a built-in premium reflecting expectations of future gas pricing over the term of the contract. The terms of the contracts can be relatively short in duration, which would typically be 12 months, or they can span longer stretches of time covering multiple years.
- These price expectations do not necessarily reflect the prevailing opportunity cost of gas for the EPL period for two reasons:
  - The term of most bilateral contracts would not be fully aligned with the EPL period. Most would probably have some overlap, but the longer duration contracts would have relatively small overlap.
  - Price expectations for future periods may not account for price shocks or unforeseen changes in market fundamentals.
- The DMIRS time series is only released biannually and is already lagging by one quarter at the time of release. There are a few issues with this:
  - Changes in the opportunity cost of gas will not be reflected in a timely manner, with the first price response in the time series being at best case nine months after a price changing event.
  - The magnitude of the price response will be muted as contracts factoring in a recent event would likely represent a small share of the weighted average of contract prices.

The lagging nature of the DMIRS time series is not so much a risk when gas prices are trending down as the projected gas price will likely be overstated and will not be a barrier to peaking generators offering capacity into the market under tight supply conditions for fear of not recovering their fuel costs. The risk manifests itself when gas prices are trending up and the lagging time series, which may not include the inflection point when prices start trending higher, significantly underestimates future gas prices.

We are currently at a point in time when the latter risk may materialise for the next EPL review. This can be seen in Figure 1, where the spot gas price series has trended strongly upwards over the last year and now exceeds the last recorded price in the DMIRS price series. If the movement in the spot gas price is representative of future 2021 DMIRS price movements, then a time series forecast relying on DMIRS pricing which is truncated in Q4 2020 is likely to underestimate the future price.

Including a risk margin in the EPL analysis somewhat mitigates the risk of understating forecast gas prices. Another mitigant is making appropriate use of the confidence intervals supplied by the time series forecast by ensuring these are reflected in the standard deviation of the gas price distribution used in the Monte Carlo sampling.

gasTrading time series

The alternative to using the DMIRS time series for projecting gas prices applicable in the WEM is the gasTrading time series. This time series mainly represents spot trades between participants that are interruptible in nature, although recently the platform has also been facilitating firm gas supply arrangements.

There are a number of issues with this time series:

- Only about 2% of gas in WA is traded through this platform.
- The depth of the market is unknown, which means that it may or may not be a liquid market. It is also possible that the liquidity of the market changes over time.
  - If this market is liquid, then it would reflect the true opportunity cost of gas and it would be appropriate to use.
  - If it is illiquid, then the following behaviour may be expected:
    - Wide spreads between the offer price and the bid price with relatively infrequent trading.
    - At times of oversupply prices would tend to be depressed relative to a more liquid market.
    - At times of high demand prices would tend to be elevated relative to a more liquid market.

Jacobs' view is this is the more appropriate time series for the following reasons:

- If the market is liquid then it already reflects the opportunity cost of gas.
- If the market is illiquid then its prices at worst case show the lower boundary of the opportunity cost of gas.
- It is updated frequently and reflects the range of prices traded in each month, including the maximum price which is most relevant for the EPL.
- It is a monthly time series with essentially no lag as trades for the current month are also disclosed.
- It is responsive to events influencing the opportunity cost of gas.
- Historically the time series has more volatility than the DMIRS series. This means a wider band of uncertainty in projected gas prices, which mitigates against the risk of underestimating an appropriate gas price as the 80^{th} percentile is ultimately used to determine the EPL.

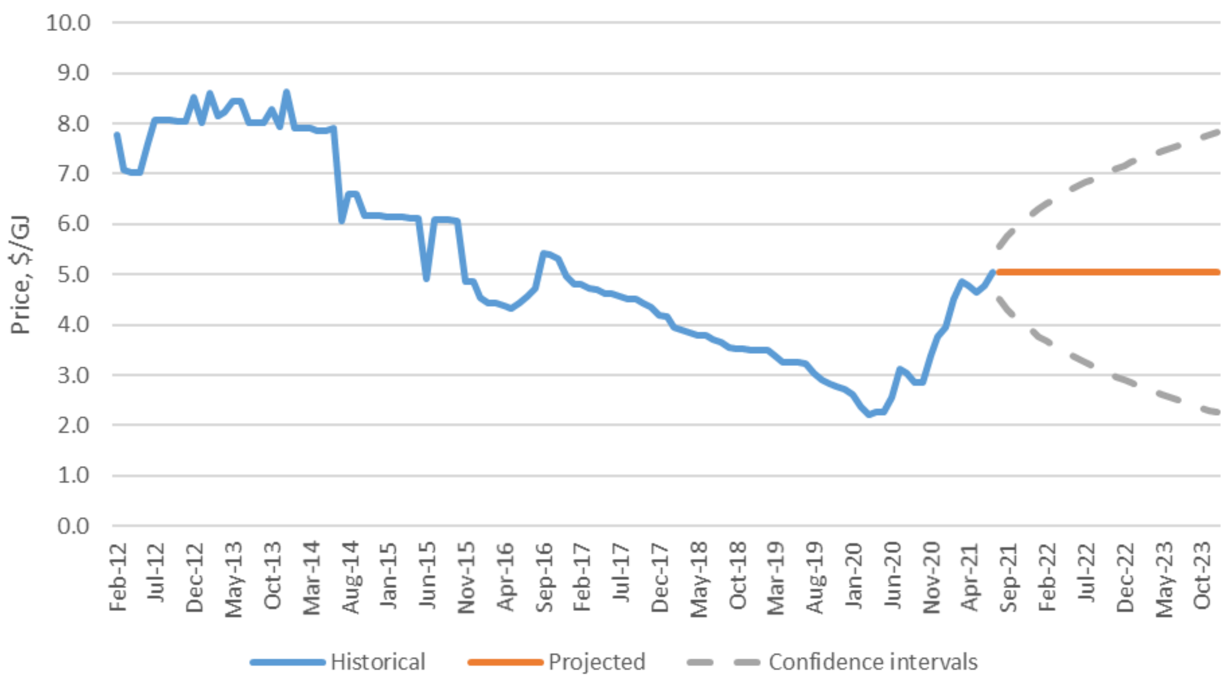
3.1 Gas price forecast for 2021-22 EPL review

We recommend the use of the maximum monthly price as published on the gasTrading platform for the reasons mentioned. Our method in forecasting gas prices has been to use a standard time series approach, also making use of dummy variables to handle historical outliers. We also trialed the inclusion of seasonality in the model, but this did not produce a good fit to the historical data.

Figure 2 shows the projected gas price based on the maximum monthly price from the gasTrading time series. The projected price is constant at $5.04/GJ, which is the last price of the time series. We trialed the inclusion of an exogenous outlier dummy variable, as well as the inclusion of a COVID-19 dummy variable and combinations of these. The best model fit was achieved by classifying July 2014, June 2015 and November 2015 prices as outliers and dropping the use of a COVID dummy variable. All of the outlier points represent the largest monthly downward price movement in the time series, and all are greater than $1/GJ. The best ARIMA model fitting the time series was one level of differencing and no auto-regressive or moving average lagged error terms[4] and using the dummy outlier as an exogenous variable.

We assume that the projected price is normally distributed, and the confidence intervals in Figure 2 are at 95% level of confidence. Assuming the EPL projection period is August 2021 until July 2022 yields the following annual gas price distribution: mean of $5.04/GJ and standard deviation of $0.63/GJ.

Figure 2: Forecast gas price using maximum monthly price from gasTrading time series



[4] The best model fit was assessed using the Akaike Information Criterion (AIC) metric, which combines goodness of fit with the rule of parsimony into one metric. One level of differencing was used to produce a stationary time series, and then the (p, 1, q) combination with the lowest AIC metric was chosen as the best fitting model.

4. Gas transmission costs

4.1 Transmission tariffs

Transmission costs on the two pipelines that will be considered in the EPL review are set by negotiation between the pipeline operators and gas shippers[5]. A review of both pipelines led to new prices being established in 2020 and 2021.

4.1.1 Dampier to Bunbury Natural Gas Pipeline

The DBNGP is a Covered (regulated) pipeline and tariffs were recently set by the ERA in 2021 to cover the base tariff. The standard full haul (T1) tariff is applicable to delivery into the Perth region downstream of compressor station CS9 and the part haul tariff (P1) is for deliveries to the north of CS9[6]. The P1 tariff also provides rules for spot trading.

The T1 and P1 tariffs are comprised of two components, a reservation component charged on capacity reserved and set at 94% of the aggregate, and a commodity component charged on volumes shipped, set at 6% of the aggregate. The P1 tariff is set according to distance, which is the distance between the inlet point and outlet point where the shipper has contracted capacity. If there is more than one inlet and/or outlet points, then the distance is calculated as the weighted average of distance between inlet and outlet points, where the weighting is determined by the contracted capacity at each point.

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

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

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

There is potential for an increased tariff of 200% of the T1 tariff for gas that falls outside the outer imbalance limit of 20% of the shipper's capacity and outside the accumulated imbalance limit of 8% that has not been rectified as per the request of the operator. In addition, charges for the overrun of gas is similar to the cost of spot gas, but unavailable overrun charges are the greater of 250% of the T1 tariff or the highest price bid for spot capacity. It is expected that a prudent shipper will not pay for any of these increased tariffs.

Based on this, we assume that the T1 tariff will have a value of $1.574/GJ over the 2021/2022 financial year, which is based on the tariff applicable from 1 July 2021.

4.1.2 Goldfields Gas Pipeline

Capacity on the GGP is partly covered and partly uncovered. Covered capacity amounts to 109 TJ/d with the current delivery configuration. Uncovered capacity, which relates to pipeline expansions, is estimated to be approximately 91 TJ/d following an expansion in 2013.

[5] The ERA does set reference tariffs (not actual tariffs) for the covered firm haulage services described below.
[6] P1 can also occur downstream of CS9 if production and consumption is south of CS9.

Covered capacity

The covered portion of GGP is understood to be at capacity, and therefore it is unlikely that a spot service could presently be negotiated.

The regulated tariffs for the covered capacity are shown in Table 1 for the base year together with the total charge in Kalgoorlie (distance 1378km). The capacity reservation capacity relates to the maximum daily capacity (MDC).

Inflation is applied annually according to the following formula (which assumes an X factor of zero).

$p_t = p_{t-1} * (1+Y)/(1+Z) * (Sep\_CPI_{t-1} / Sep\_CPI_{t-2})$

Where:

p_t is the relevant charge in the year t in which the adjustment occurs.
p_{t-1}s the charge for the year prior to t-1.

Y is a number no greater than 2%

Z is 0.0114 (1.14% being the forecast annual percentage inflation rate used in the final decision).

Sep_CPI $_{t-1}$ is the CPI all groups, weighted average of eight capital cities for the September quarter one year prior to year t.

Sep_CPI$_{t-2}$ is the CPI for the September quarter two years prior to year t.

Applying this formula, and assuming a CPI increase of 0.496% per quarter (2.0% pa) and 2.0% for the Y variable gives an average cost in 2022 of gas transmission to Kalgoorlie of $1.399/GJ in June 2021 dollars.

Table 1: GGP covered tariffs (June 2021 dollars)

	Toll Tariff $/GJ	Capacity Reservation Tariff $/GJ MDC km	Throughput Tariff $/GJ km	Cost at 100% load factor in Kalgoorlie (1378 km) $/GJ
Covered capacity, 2021 tariff	0.118465	0.000718	0.000195	1.376579
Covered capacity, Projected 2022 tariff	0.120345	0.000730	0.000198	1.398887
Average 2021/22 covered tariff				1.387733

Uncovered capacity

Stakeholder feedback from the last EPL review was to include the Parkeston calculation using the uncovered tariff, which is more costly than the covered tariff. Table 2 shows the uncovered tariff as reported on the APA website, and includes a projection into 2022 based on the CPI adjustment formula presented above and then converted into June 2021 dollars.

Table 2: GGP uncovered tariffs (June 2021 dollars)

	Toll Tariff $/GJ	Capacity Reservation Tariff $/GJ MDC km	Cost at 100% load factor in Kalgoorlie (1378 km) $/GJ
Uncovered capacity, 2021 tariff	0.39390	0.003000	4.52790
Uncovered capacity, Projected 2022 tariff	0.40015	0.003048	4.59975
Average 2021/22 uncovered tariff			4.563825

4.1.3 Transmission costs

Based on the practice in the last EPL review for dealing with uncertainty in transmission costs the final distributions are as follows:

- For DBNGP full haul, the estimated minimum spot price ($1.574/GJ) converted into a range by adding a normal distribution with a standard deviation of $0.15/GJ.
- For the covered capacity of GGP the estimate at 100% load factor is $1.388/GJ, which is converted into a range by adding a normal distribution with a standard deviation of $0.15/GJ.
- For the uncovered capacity of GGP the estimate at 100% load factor is $4.564/GJ, which is converted into a range by adding a normal distribution with a standard deviation of $0.15/GJ.

4.2 Daily gas load factor

There is uncertainty associated with the daily load factor applicable to gas turbines, and in our view this is best modelled as a distribution rather than being represented as a static number.

Our suggested probability distribution used to represent the uncertainty of the daily gas supply load factor is shown in Figure 3. The mode of the continuous distribution is at 95% with an 80% confidence range between 80% and 98%. There is a 0.005% probability of a value at 60%. The mean of the composite daily load factor distribution is 89.91%. This approach had been used in reviews from 2013 to 2018.

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

Figure 3: Capped lognormal distribution for modelling spot gas daily load factor uncertainty