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Mr Greg Watkinson
Chief Executive Officer
Economic Regulation Authority
Level 4, Albert Facey House
469 Wellington Street
PERTH WA 6000

Dear Greg,

SUBMISSION UNDER CLAUSE 6.20.10

In accordance with clause 6.20.10 of the Wholesale Electricity Market Rules (Market Rules), the IMO submits its final report for the 2014 Energy Price Limits Review. The final report comprises the covering report prepared by the IMO and the Final Report of its consultant, Sinclair Knight Merz (now known as Jacobs SKM).

In developing its Final Report, Jacobs SKM prepared a Draft Report, which was released for public consultation in March 2014. The IMO received one submission from Community Electricity during the public consultation period, which supported the Draft Report and raised no issues.

Under the Market Rules, Western Power is required to provide the IMO with revised Loss Factors for the 2014/15 Financial Year by 1 June 2014. As these Loss Factors are not yet available, Jacobs SKM has used the current (2013/14 Financial Year) Loss Factor for Pinjar in its calculation of the proposed Energy Price Limits.

The IMO considers that the Energy Price Limits proposed by Jacobs SKM in its Final Report should be adjusted to reflect any change from the current Pinjar Loss Factor (1.0312) to the Loss Factor determined by Western Power for the 2014/15 Financial Year, once the latter value becomes available.

The IMO notes that a similar adjustment was made to the prices proposed by Jacobs SKM in its Final Report for the 2013 Review. Based upon historical experience and preliminary advice from Western Power, it is expected that the impact on the Energy Price Limits will be minor.

Accordingly, the IMO proposes the following final revised values for the Energy Price Limits (PLF_Rev is the revised Pinjar Loss Factor for the 2014/15 Financial Year):

- Maximum STEM Price: ($332.46 * 1.0312 / PLF_Rev) / MWh (rounded to the nearest dollar); and

- Alternative Maximum STEM Price:
  - Non-Fuel Coefficient: 92.78 * 1.0312 / PLF_Rev (rounded to two decimal places); and
  - Fuel Coefficient: 19.494 * 1.0312 / PLF_Rev (rounded to three decimal places).

Assuming no change to the Pinjar Loss Factor the proposed values would be:

- $332/MWh for the Maximum STEM Price (an increase from the current price of $305/MWh); and
- $535/MWh for the Alternative Maximum STEM Price, assuming a distillate price of $22.70/GJ (a decrease from the currently approved price of $566/MWh for this distillate price).

  The corresponding price components for the Alternative Maximum STEM Price would be:

- $92.78/MWh + 19.494 multiplied by the delivered distillate fuel cost in $/GJ.

The IMO proposes that the revised Energy Price Limits take effect from 8:00 AM on 1 July 2014. If approved by the ERA the new values will be posted on the IMO website in advance of that date to allow Market Participants to update their standing bids on the basis of the revised Energy Price Limits (clause 6.20.11(b) of the Market Rules). The IMO plans to publish the values on its website on 24 June 2014.

In order to meet this timetable, the IMO requests the outcome of the ERA's decision by 23 June 2014 (pursuant to clause 2.26.1(b) of the Market Rules).

If you have any queries in relation to the review, please do not hesitate to contact me.

Yours sincerely

ALLAN DAWSON
CHIEF EXECUTIVE OFFICER

22 May 2014

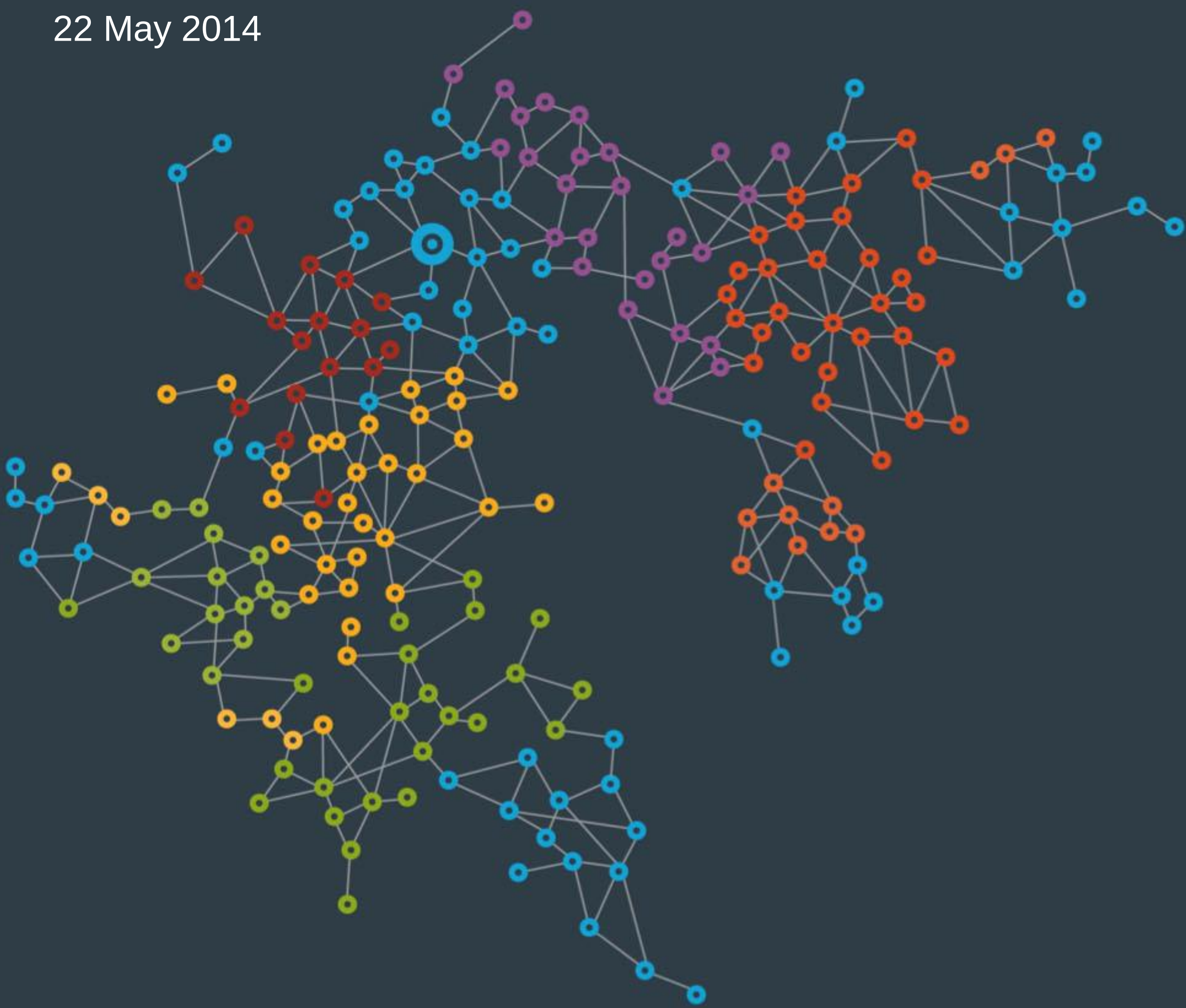
INDEPENDENT MARKET OPERATOR

Independent Market Operator

Final Report

2014 Review of the Energy Price Limits for the Wholesale Electricity Market

22 May 2014



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Document details

Report Title:	Final Report: 2014 Review of the Energy Price Limits for the Wholesale Electricity Market
Release Status:	Public
Confidentiality Status:	Public domain

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1. Background

Clause 6.20.6 of the Wholesale Electricity Market (WEM) Rules (Market Rules) requires the Independent Market Operator (IMO) to annually review the appropriateness of the values of the Energy Price Limits. In conducting the review, the IMO may propose revised values for the Maximum Short Term Energy Market (STEM) Price and the Alternative Maximum STEM Price. The IMO must calculate the revised values using the methodology set out in clause 6.20.7 of the Market Rules.

The IMO engaged Sinclair Knight Merz (now known as Jacobs SKM), an independent consultant, to assist the IMO in undertaking its annual review of the Energy Price Limits for 2014. Jacobs SKM was also engaged in 2013 to undertake this task.

The 2014 review included:

- determining whether the cost assumptions and probability levels adopted in the modelling are still appropriate;
- revising the maximum prices by conducting an analysis of the relevant costs; and
- the preparation of a Draft Report and Final Report.

The review of the Energy Price Limits is now complete. The Final Report required under clause 6.20.10 of the Market Rules comprises this report and Jacobs SKM's Final Report. A copy of Jacobs SKM's Final Report is available on the IMO website: IMO - 2014 Energy Price Limits Review.

2. Summary of the IMO's Draft Report

2.1. Overview

Two price caps were reviewed, the Maximum STEM Price, which applies when non-liquid fuel (typically gas) is used by the highest cost peaking plant, and the Alternative Maximum STEM Price, which applies when liquid fuel is required to be used.

The 2014 review has:

- continued with the methodology for setting the Energy Price Limits applied in 2013;
- updated the impact of the carbon price on dispatch cycle cost so that the Energy Price Limits reflect the legislated carbon price of $25.40/t$CO_2$e from 1 July 2014, and separately provided Energy Price Limits without any carbon price impact;
- updated the O&M costs for operating 40 MW gas turbines for both the industrial and aero derivative types by escalating the previously advised costs and accounting for movements in foreign exchange rates, as no further information was obtainable;
- retained assumptions on average heat rates at maximum and minimum capacity from the 2013 Review;

- developed the gas price distributions that, for the previous four reviews, were provided by ACIL Tasman, using a similar methodology where possible, and in particular:
  - used spot gas prices in the calculation of the Maximum STEM Price, as the rationale remained unchanged;
  - continued to adopt the same approach for defining the distributions for the spot gas transport cost and the daily load factor; and
  - modified the methodology for determining the spot gas price range and based it on a statistical model that estimates the impact of the contract price movements on the gasTrading maximum spot price distribution, using publicly available information regarding gas prices in WA and expected movements in contract prices, allowing for some adjustment to cover other material short term supply/demand factors;
- used the following gas pricing parameters deemed applicable to the spot purchase and transport of gas for peaking purposes, based on the methodology described in the bullet point above:
  - defined the daily load factor to have an 80% confidence range between 80% and 98% using a truncated lognormal distribution, with a mean value of 89.9%, and a most likely value of 95.0%;
  - sampled from a discrete gas commodity cost distribution between \$2/GJ and \$24/GJ/[1] with an 80% confidence range of \$7.52/GJ to \$11.12/GJ, a mean value of \$9.31/GJ and a most probable value of \$8.50/GJ; and
  - used a lognormal distribution of spot gas transport cost to the Perth area between \$1.00/GJ and \$3.00/GJ with an 80% confidence range between \$1.46/GJ and \$2.15/GJ, a mean value of \$1.795/GJ and a most likely value of \$1.735/GJ;
- used historical market observations from the 2013 calendar year to estimate distributions for starting frequency, average run time, generation per dispatch cycle and minimum capacity for Pinjar and Parkeston;
- continued the previous treatment of start-up costs and the cost uncertainty, by setting the recommended price to cover 80% of possible outcomes with run times of between 0.5 and 6 hours;
- removed road freight from the variable fuel component of the Alternative Maximum STEM Price as the road freight is relatively static over a one year period, but retained it in the fuel transport cost component and did not vary it with the change in distillate price;
- used the standard deviation of daily Singapore gasoil prices to assess the variation in distillate price, whereas in previous reviews the monthly standard deviation for Brent crude was used to approximate this standard deviation; and
- recommended a set of new values in accordance with the Market Rules.

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

The proposed revised values presented in the Draft Report were $332/MWh for the Maximum STEM Price and, assuming a distillate price of $22.70/GJ, $535/MWh for the Alternative Maximum STEM Price. The corresponding price components for the Alternative Maximum STEM Price were:

$92.78/MWh + 19.494 multiplied by the Net Ex Terminal[2] distillate fuel cost in $/GJ.

3. Public Consultation Process

As required by the Market Rules, on 14 March 2014 the IMO published a Draft Report on the IMO website proposing the revised values for the Energy Price Limits. The IMO published a notice in the West Australian newspaper on this day, requesting submissions on the Draft Report from all sectors of the Western Australian energy industry, including end-users. The consultation period was six weeks in length and closed on 30 April 2014.

The IMO received one submission from Community Electricity during the public consultation period, which supported the Draft Report and raised no issues. A copy of this submission is available on the IMO website: IMO - 2014 Energy Price Limits Review.

3.1. Public Workshop

The IMO invited interested parties to participate in a public workshop on the Energy Price Limits Draft Report, to be held on 7 April 2014. Only two people responded to the IMO's invitation, and when contacted these people had no specific issues or questions to discuss and did not consider that the workshop should be held on their account. On this basis the workshop was cancelled.

4. Changes from the Draft Report

4.1. Summary of Changes in Jacobs SKM's Final Report

The proposed values for the Energy Price Limits in Jacobs SKM's Final Report are unchanged from the values proposed in the Draft Report.

4.2. Adjustments to Reflect 2014/15 Loss Factors

Under the Market Rules, Western Power is required to provide the IMO with revised Loss Factors for the 2014/15 Financial Year (FY2014/15) by 1 June 2014. As these Loss Factors are not yet available, Jacobs SKM has used the current (FY2013/14) Loss Factor for Pinjar in its calculation of the proposed Energy Price Limits.

The IMO considers that the Energy Price Limits proposed by Jacobs SKM in its Final Report should be adjusted to reflect any change from the current Pinjar Loss Factor (1.0312) to the Loss Factor determined by Western Power for FY2014/15, once the latter value becomes available.

The IMO notes that a similar adjustment was made to the prices proposed by Jacobs SKM in its Final Report for the 2013 Review. Based upon historical experience and preliminary advice from Western Power, it is expected that the impact on the Energy Price Limits will be minor.

[2] Wholesale price for distillate in Perth, Western Australia, after deduction of excise rebate and excluding GST. This price does not include road freight costs.

Consistent with this adjustment, the IMO proposes the following amendments to the parameters provided in Jacobs SKM's Final Report to meet the requirements of clause 6.20.7(b) of the Market Rules:

- Loss Factor (clause 6.20.7(b)(v)) should be updated to reflect the revised Pinjar Loss Factor; and
- Risk Margin (clause 6.20.7(b)(i)) should be calculated in accordance with the formula prescribed in clause 6.20.7(b), using the revised Loss Factor and the Variable O&M, Heat Rate and Fuel Cost values proposed by Jacobs SKM.

5. Conclusions

5.1. Energy Price Limits

The IMO proposes the following final revised values for the Energy Price Limits (PLF_Rev is the revised Pinjar Loss Factor for FY2014/15):

- Maximum STEM Price: ($332.46 * 1.0312 / PLF_Rev) / MWh (rounded to the nearest dollar);
- Alternative Maximum STEM Price:
  - Non-Fuel Coefficient: 92.78 * 1.0312 / PLF_Rev (rounded to two decimal places); and
  - Fuel Coefficient: 19.494 * 1.0312 / PLF_Rev (rounded to three decimal places).

Assuming no change to the Pinjar Loss Factor the proposed values would be:

- $332/MWh for the Maximum STEM Price (an increase from the current price of $305/MWh); and
- $535/MWh for the Alternative Maximum STEM Price, assuming a distillate price of $22.70/GJ (a decrease from the currently approved price of $566/MWh for this distillate price).

The IMO proposes that the revised Energy Price Limits take effect on 1 July 2014. The new values will be posted on the IMO website in advance of that date to allow Market Participants to update their standing bids on the basis of the revised Energy Price Limits.

In order to meet this timetable, the Economic Regulation Authority's approval is sought by 23 June 2014. Once approved, the new values for Energy Price Limits will take effect from the date specified in the notice posted by the IMO on its website.

A summary of the input parameters and key outcomes of the Energy Price Limit reviews for each year since 2007 is available in Appendix 1 of this report.

5.2. Energy Price Limits Without Carbon Price Impact

Jacobs SKM has also calculated Energy Price Limits for FY2014/15 under the assumption that no carbon price is applicable during that Financial Year. The resulting values are provided in Appendix F of SKM Jacob's Final Report.

In summary, if no carbon price was applicable during FY2014/15 then (assuming no change to the

Pinjar Loss Factor):

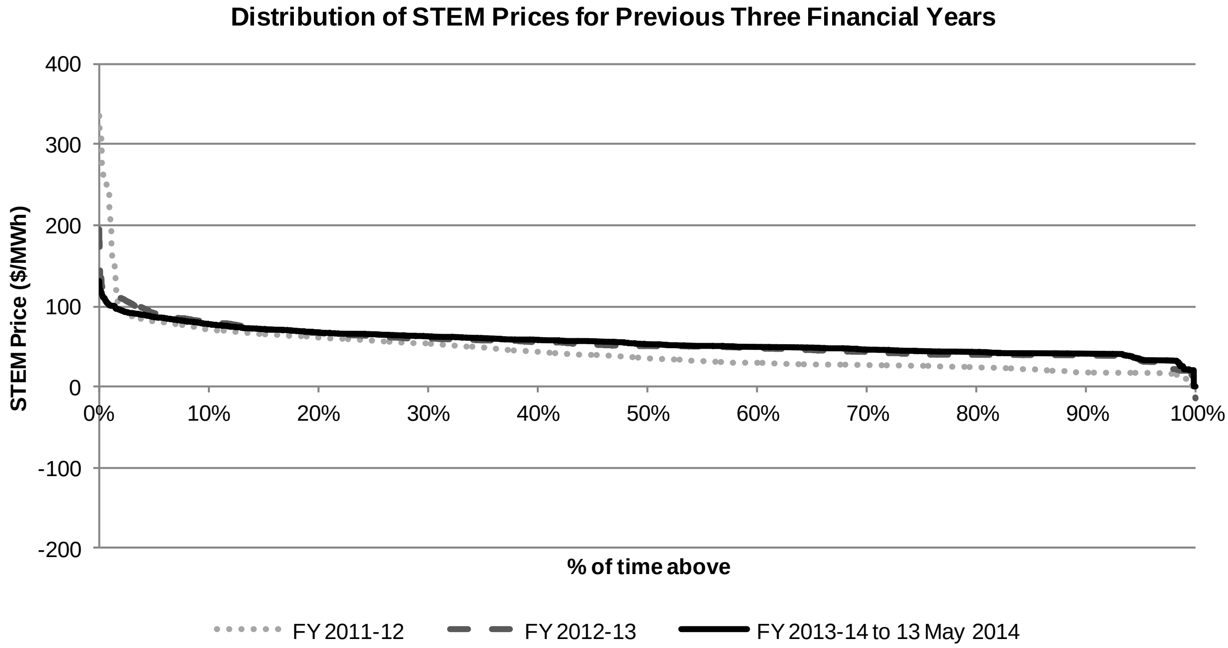
- the Maximum STEM Price would be reduced from $332/MWh to $306/MWh; and
- the revised equation for the Alternative Maximum STEM Price would be:

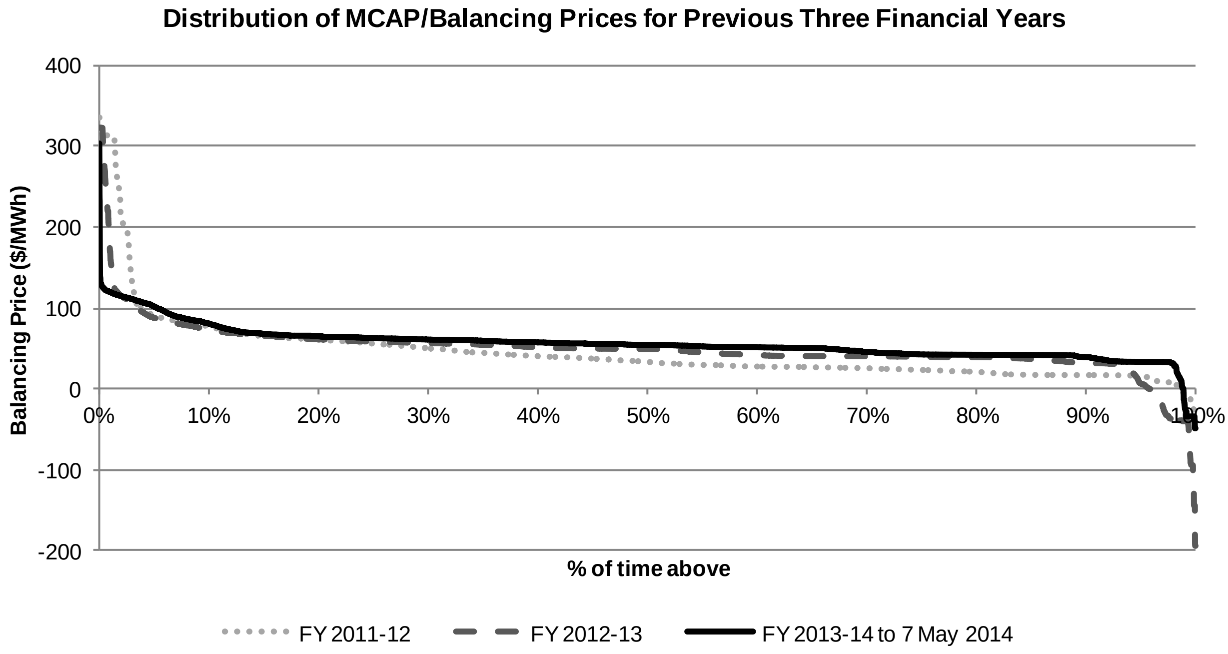
  $58.71/MWh + 19.483 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

  Assuming a distillate price of $22.70/GJ, the Alternative Maximum STEM Price would be reduced from $535/MWh to $501/MWh.

5.3. Effect of Price Limits on STEM and Balancing Prices

The following two charts show the distributions of STEM Clearing Prices and Marginal Cost Administered Prices (MCAP) or Balancing Prices (which replaced MCAP on 1 July 2012) for the previous three Financial Years.





STEM Clearing Prices generally showed an increase from FY2011/12 to FY2012/13 with the introduction of a carbon price on 1 July 2012, and a slight increase from FY2012/13 to FY2013/14. However, the introduction of the Balancing Market, also on 1 July 2012, appears to have reversed that trend for periods of highest prices:

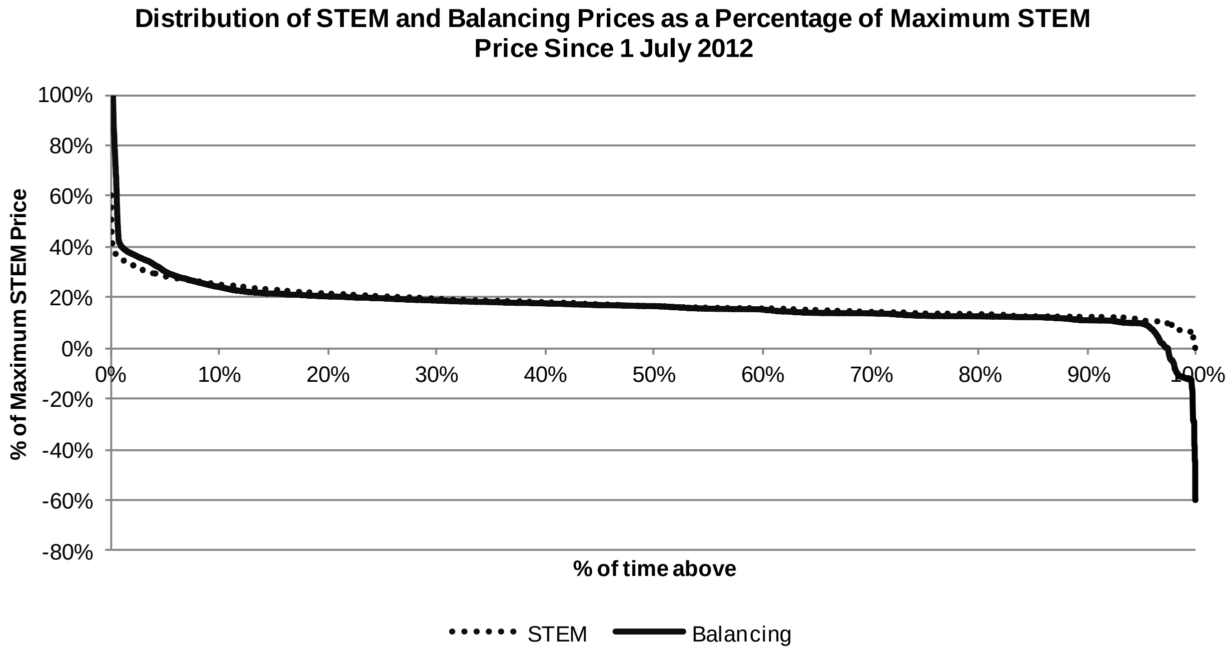
- in FY2011/12 STEM Clearing Prices were above $200/MWh for 1.07% of Trading Intervals;
- the highest STEM Clearing Price in FY2012/13 was $195.05/MWh; and
- the highest STEM Clearing Price in FY2013/14 was $130.13/MWh.

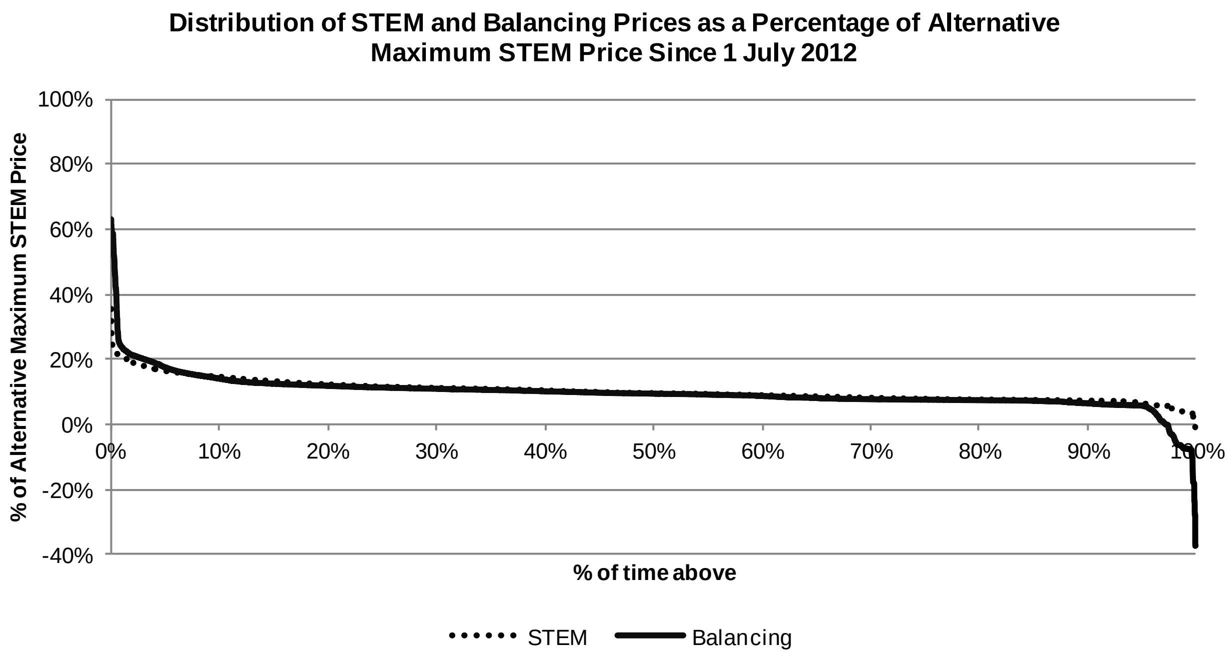
The proportion of Trading Intervals with STEM Clearing Prices above $120/MWh reduced from 1.58% in FY2011/12 to 0.55% in FY2012/13 and then to just 0.06% in FY2013/14. MCAP and Balancing Prices show a similar trend; although the price has reached the Maximum STEM Price in all three years, it is also the case that:

- the MCAP was above $120/MWh for 3.15% of Trading Intervals in FY2011/12;
- the Balancing Price was above $120/MWh for 1.63% of Trading Intervals in FY2012/13; and
- the Balancing Price was above $120/MWh for 0.94% of Trading Intervals in FY2013/14.

Incidents of high prices, for which the Energy Price Limits are relevant, therefore appear to be reducing in frequency.

The following two charts show the distributions of the STEM Clearing Prices and Balancing Prices as proportions of the Maximum STEM Prices and Alternative Maximum STEM Prices since 1 July 2012 (Balancing Market Commencement Day).





Since the introduction of the Balancing Market on 1 July 2012, the Balancing Price has never exceeded the Maximum STEM Price, has been equal to it for 0.07% of Trading Intervals, and has been greater than 90% of the Maximum STEM Price for just 0.22% of Trading Intervals. For 99% of Trading Intervals, the Balancing Price was less than 40% of the Maximum STEM Price. The highest it has been relative to the Alternative Maximum STEM Price is 63.3%. The highest that the STEM Clearing Price has been relative to the Maximum STEM Price is 60.4% and, relative to the Alternative Maximum STEM Price, 35.7%.

The Energy Price Limits therefore do not appear to be having a constraining effect on market prices.

5.4. Potential Areas for Review of the Market Rules

In its Final Report, Jacobs SKM recommended that clause 6.20.7 be reformulated to describe more clearly the use of probability distributions and a choice of a percentile value to derive the Energy Price Limits, rather than defining a Risk Margin and adding it to the expected value of the combined distribution of average dispatch cycle cost, or to a function of mean values.

The IMO is considering this and other potential amendments to the Market Rules relating to the Energy Price Limits, which have been raised in previous reviews of the Energy Price Limits and in the ERA's recent review of the methodology for setting the Energy Price Limits.

Appendix 1: Input parameters and key outcomes of the 2007 to 2014 reviews

A comparison between the input parameters and key outcomes in the 2007- 2014 reviews is presented in Table 1 and 2. A summary of the monthly changes to the Alternative Maximum STEM Price is presented in Table 3.

Table 1: Input parameters and key outcomes in the 2007 – 2014 reviews

	2007	2008	2009	2010	2011	2012	2013	2014
Heat rate	Based on estimate of varying heat rate over a dispatch cycle	Fixed at the heat rate at minimum operating capacity	Fixed at the heat rate at minimum operating capacity	Fixed at the heat rate at minimum operating capacity	Fixed at the heat rate at minimum operating capacity	Fixed at the heat rate at minimum operating capacity	Fixed at the heat rate at minimum operating capacity	Fixed at the heat rate at minimum operating capacity
Industrial type								
Gas[3]	18.1 to 13.1 GJ/MWh	18.1 GJ/MWh	18.1 GJ/MWh	20.1 GJ/MWh	20.1 GJ/MWh	18.6 GJ/MWh	18.6 GJ/MWh	19.2 GJ/MWh
Distillate3	19.0 to13.8 GJ/MWh	18.2 GJ/MWh	18.2 GJ/MWh	20.1 GJ/MWh	20.1 GJ/MWh	18.6 GJ/MWh	18.7 GJ/MWh	19.2 GJ/MWh
Aero derivative								
Gas3	15.7 to 10.7 GJ/MWh	15.7 GJ/MWh	15.7 GJ/MWh	17.8 GJ/MWh	17.8 GJ/MWh	13.4 GJ/MWh	13.4 GJ/MWh	12.4GJ/MWh
Distillate3	16.5 to 15.7 GJ/MWh	15.7 GJ/MWh	15.7 GJ/MWh	17.8 GJ/MWh	17.8 GJ/MWh	13.4 GJ/MWh	13.4 GJ/MWh	12.4GJ/MWh

[3] Rounded to one decimal place.

	2007	2008	2009	2010	2011	2012	2013	2014
Gas costs								
Gas contract price	$6/GJ (4.50-7.50)	$8/GJ (6.00-10.00)	$8/GJ (6.00-10.00)	$8/GJ (5.00-12.00)	$6.50/GJ (4.60-12.20)[4]	$6.48/GJ (5.33-12.17)	$6.60/GJ (4.98-11.54)	$8.50/GJ (7.52-11.12)
Gas emission cost								
South West						$1.27/GJ	$1.34/GJ	$1.41/GJ
Goldfields						$1.26/GJ	$1.33/GJ	$1.40/GJ
Gas transport								
South West	$1.40/GJ	$1.45/GJ	$1.47/GJ	$1.78/GJ	$1.77/GJ	$1.82/GJ	$1.74/GJ	$1.74/GJ
Goldfields	$3.17/GJ	$3.26/GJ	$3.35/GJ	$4.15/GJ	$5.00/GJ	$5.67/GJ	$5.91/GJ	$6.14/GJ
Load factor								
Load factor range	70% (50% to 90 %)	unchanged	75% (70-85%)	94.4% (80-100%)	95.0% (80-98%)	95.0% (80-98%)	95.0% (80-98%)	95.0% (80-98%)
Distillate costs								
Distillate price[5]	$24/GJ	$32/GJ	$18/GJ	$19/GJ	$23/GJ	$24/GJ	$22/GJ	$23/GJ
Distillate Emission Cost						$1.72/GJ	$1.68/GJ	$1.77/GJ

4 Based on the most probable value for spot gas and the 80% confidence range. Note that gas contract prices prior to 2010 have been presented as mean values.
5 Rounded to nearest integer.

	2007	2008	2009	2010	2011	2012	2013	2014
O&M costs								
Industrial type	$8.07/MWh	$9.27/MWh	$14.04/MWh	$14.31/MWh	$17.57/MWh	$14.49/MWh	$10.02/MWh	$13.58/MWh
Aero derivative	$180/hr (maintenance only)	$210/hr (maintenance only)	$196/hr (time based discounted cost)	$201/hr (time based discounted cost)	$195/hr (time based discounted cost)	$194/hr (time based discounted cost)	$199/hr (time based discounted cost)	$201/hr (time based discounted cost)
Starts per year (average)								
Industrial type	160	145	160	157	157.7	160.8	76.4	71.2
Aero derivative	Taken into account in a different way (1 start equivalent to only 1 running hour)	Taken into account in a different way (1 start equivalent to only 1 running hour)	Taken into account in a different way (1 start equivalent to only 1 running hour)	Taken into account in a different way (1 start equivalent to only 1 running hour)	Taken into account in a different way (1 start equivalent to only 1 running hour)	Taken into account in a different way (1 start equivalent to only 1 running hour)	Taken into account in a different way (1 start equivalent to only 1 running hour)	Taken into account in a different way (1 start equivalent to only 1 running hour)

Table 2: Key Outcomes from the 2007 – 2014 reviews

	2007	2008	2009	2010	2011	2012	2013	2014
Non-Liquid								
Maximum STEM Price	$206/MWh	$286/MWh	$276/MWh	$336/MWh	$314/MWh	$323/MWh	$305/MWh	$332/MWh
Annual percentage change	+34.44%[6]	+38.83%	-3.50%	+21.74%	-6.55%	+2.87%	-5.57%	+8.85%
Probability level	80%	80%	80%	80%	76%	80%	80%	80%
Margin over expected value	15.1%	13.9%	14.0%	20.0%	16.3%	18.7%	22.1%	12.5%
Liquid								
Alternative Maximum STEM Price (see monthly changes in the table below)	$498/MWh	$763/MWh	$469/MWh	$446/MWh	$533/MWh	$547/MWh	$500/MWh[7]	$535/MWh
Annual percentage change	+3.75%6	+53.21%	-38.53%	-4.90%	+19.51%	+2.63%	-8.59%	+7.00%
Alternative Maximum STEM Price for $22.70/GJ distillate price	$475/MWh	$516/MWh	$553/MWh	$528/MWh	$535/MWh	$529/MWh	$516/MWh	$535/MWh
Probability level	90%	90%	90%	80%	80%	80%	80%	80%
Margin over expected value	14.5%	10.7%	19.3%	6.2%	6.0%	7.8%	8.4%	5.8%

[6] Based on the initially published prices (21 September 2006) of $153.73 (Maximum STEM Price) and $480.00 (Alternative Maximum STEM Price).
[7] The IMO's Final Report (available at http://www.imowa.com.au/rules/other-wem-consultation-documents/2013-energy-price-limits-review) was published on 16 May 2013 and specified a price of $495/MWh, based on a distillate price of $21.65/GJ. The actual Alternative Maximum STEM Price for July 2013 was recalculated as $500/MWh using an updated distillate price of $21.96/GJ.

Table 3: Monthly Changes to the Alternative Maximum STEM Price ($/MWh)

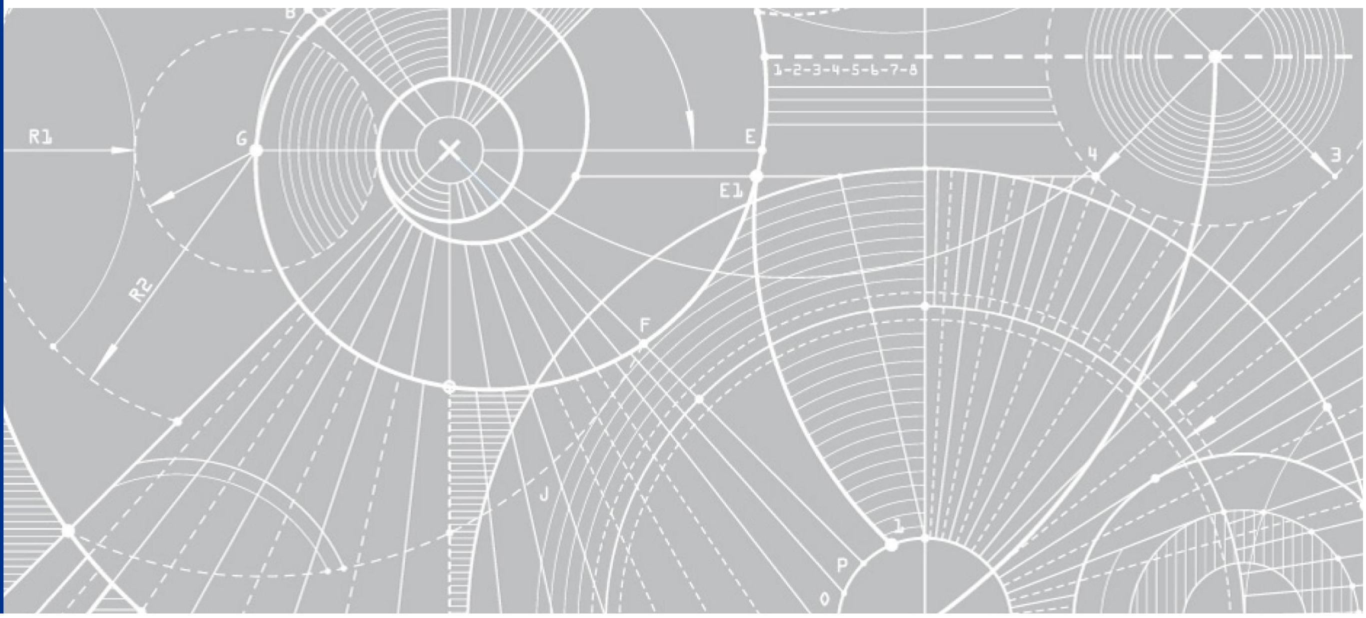
	2007	2008	2009	2010	2011	2012	2013	2014
January		532	592	454	416	546	535	552
February		550	512	458	418	552	525	555
March		569	463	464	435	559	515	563
April		573	423	466	476	558	525	571
May		593	411	473	520	564	523	566
June		632	405	486	546	571	512	
July		692	416	496	549	547	500	
August		743	439	501	536	528	500	
September		779	450	498	522	510	521	
October		763	469	446	524	510	545	
November	498	722	459	438	533	528	560	
December	498	653	458	426	534	540	558	

Energy Price Limits for the Wholesale Electricity Market in Western Australia

INDEPENDENT MARKET OPERATOR

SH43582 | Final

13 May 2014



Jacobs SKM 2014 Energy Price Limits Review

Project no:	SH43582
Document title:	Jacobs SKM 2014 Energy Price Limits Review
Revision:	Final
Date:	13 May 2014
Client name:	Independent Market Operator
Project manager:	Nicola Falcon
Author:	Nicola Falcon, Richard Lewis
File name:	Jacobs SKM 2014 Energy Price Limits Review Final

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Contents

Executive summary

Once a year, the Independent Market Operator (IMO) is required to review the Energy Price Limits in the Wholesale Electricity Market. Sinclair Knight Merz (Jacobs SKM) was engaged by the IMO to conduct the 2014 review for the year commencing 1 July 2014. This assignment was conducted in a similar fashion to that conducted by Jacobs SKM in 2013.

For the 2014 review, Jacobs SKM has:

- Continued with the basis for setting the Energy Price Limits as applied in 2013.
- Updated the impact of the carbon price on dispatch cycle cost so that the Energy Price Limits reflect the legislated carbon price of $25.40/tCO$_2$e from 1 July 2014, and separately provided Energy Price Limits without any carbon price impact.
- Updated the O&M costs for operating 40 MW gas turbines for both the industrial and aero derivative types by escalating the previously advised costs and accounting for movements in foreign exchange rates, as no further information was obtainable.
- Retained assumptions on average heat rates at maximum and minimum capacity from the 2013 review.
- Developed the gas price distributions that, for the previous four reviews, were provided by ACIL Tasman, using a similar methodology where possible. In particular:
    - the rationale for using spot gas prices in the calculation of the Maximum STEM Price remains unchanged
    - the approach for defining the distributions for the spot gas transport cost and the daily load factor has continued to be adopted
    - the methodology for determining the spot gas price range has been modified and is now based on a statistical model that estimates the impact of the contract price movements on the gasTrading maximum spot price distribution. The model is based on publicly available information regarding gas prices in WA and expected movements in contract prices, allowing for some adjustment to cover other material short term supply/demand factors.
- Used the following gas pricing parameters deemed applicable to the spot purchase and transport of gas for peaking purposes, based on the methodology described in the bullet point above:
    - Defined the daily load factor to have an 80% confidence range between 80% and 98% using a truncated lognormal distribution, with a mean value of 89.9%, and a most likely value of 95.0%;
    - Sampled from a discrete gas commodity cost distribution between $2/GJ and $24/GJ/[1] with an 80% confidence range of $7.52/GJ to $11.12/GJ, a mean value of $9.31/GJ and a most probable value of $8.50/GJ;
    - Used a lognormal distribution of spot gas transport cost to the Perth area between $1.00/GJ and $3.00/GJ with an 80% confidence range between $1.46/GJ and $2.15/GJ, a mean value of $1.795/GJ and a most likely value of $1.735/GJ.
- Used historical market observations from the 2013 calendar year to estimate distributions for starting frequency, average run time, generation per dispatch cycle and minimum capacity for Pinjar and Parkeston.
- Continued the previous treatment of start-up costs and the cost uncertainty. The recommended price is set to cover 80% of possible outcomes with run times of between 0.5 and 6 hours.
- Removed road freight from the variable fuel component of the Alternative STEM Price as the road freight is relatively static over a one year period. The road freight component is retained in the fuel transport cost component for the Alternative STEM Price. It is not varied with the change in distillate price.

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

- Used the standard deviation of daily Singapore gasoil prices to assess the variation in distillate price since it is the Singapore gasoil price that is used to estimate the Ex Terminal price in the analysis. The uncertainty and level of the distillate price is relevant to the extent that it is used to cap the extreme spot gas prices at the level where the dispatch cycle cost would be equal for gas and for distillate firing for the nominated gas turbine technology and location. Hence variation in distillate price is used in determining the Maximum STEM Price, not the Alternative Maximum STEM Price. In previous reviews, the monthly standard deviation for Brent crude was used to approximate this standard deviation.

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

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

Component	Units	Maximum STEM Price	Alternative Maximum STEM Price
Mean Variable O&M	$/MWh	$42.27	$42.27
Mean Heat Rate	GJ/MWh	19.267	19.319
Mean Fuel Cost (Including emissions cost)	$/GJ	$13.60	$24.81
Loss Factor		1.0312	1.0312
Before Risk Margin 6.20.7(b) [2]	$/MWh	$295.09	$505.79
Risk Margin added	$/MWh	$36.91	$29.21
Risk Margin Value	%	12.5%	5.8%
Assessed Maximum Price	$/MWh	$332	$535

Exec Table 2 summarises the prices that have applied since October 2011 and the subsequent results obtained by using the various methods. New values are rounded to the nearest dollar which is consistent with previous practice.

Exec Table 2 Summary of price cap analysis

No.	History of proposed and published prices	Maximum STEM Price ($/MWh)	Alternative Maximum STEM Price ($/MWh)	Comment
1	Published Prices from 1 October 2011	$314	$524	From IMO website.
2	Published Prices from 1 July 2012	$323	$547	From IMO website.
3	Published Prices from 1 July 2013	$305	$500	From IMO website
4	Published Prices from 1 May 2014	$305	$566	From IMO website[3]
5	Proposed prices to apply from 1 July 2014	$332	$535	Based on $22.70/GJ for distillate, ex terminal.
6	Probability level as Risk Margin basis	80%	80%	

Notes: (1) As required in clause 6.20.7(b) these are the proposed price caps to apply from 1 July 2014 based on a projected Net Ex Terminal wholesale distillate price of $1.258/litre excluding GST ($22.70/GJ).
(2) In row 6, the probability levels that are proposed to be applied to determine the Risk Margin for setting the price caps in accordance with the Market Rules.

[2] Mean values have been rounded to the values shown in the Table for the purpose of this calculation
[3] http://www.imowa.com.au/market-data-pricelimits accessed 5 May 2014

The recommended values are $332/MWh for the Maximum STEM Price and $535/MWh for the Alternative Maximum STEM Price at $22.70/GJ Net Ex Terminal distillate price (i.e. net of excise rebate and excluding GST).

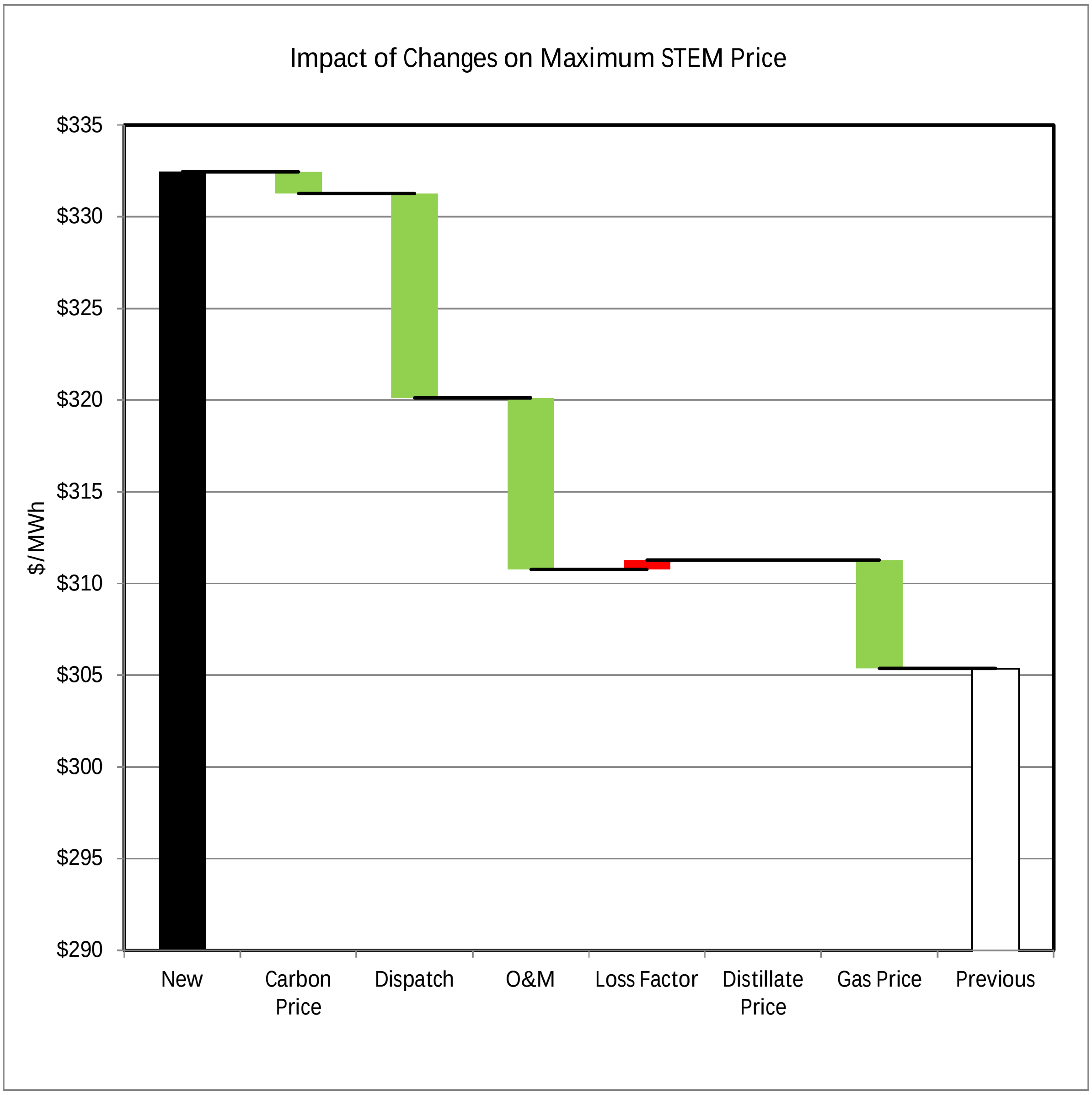
The corresponding price components for the Alternative Maximum STEM Price are:

> $92.78/MWh + 19.494 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

The increase in the Maximum STEM Price since last year's assessment has been primarily due to the AUD:US exchange rate impact on O&M costs and a reduction in the assumed average run time and minimum capacity for Pinjar.

The changes in spot gas prices have also had a slight positive impact on the Maximum STEM Price, of $5.91/MWh[4]. The relative contributions to the change in the Maximum STEM Price are illustrated in the waterfall diagram in Exec Figure 1.

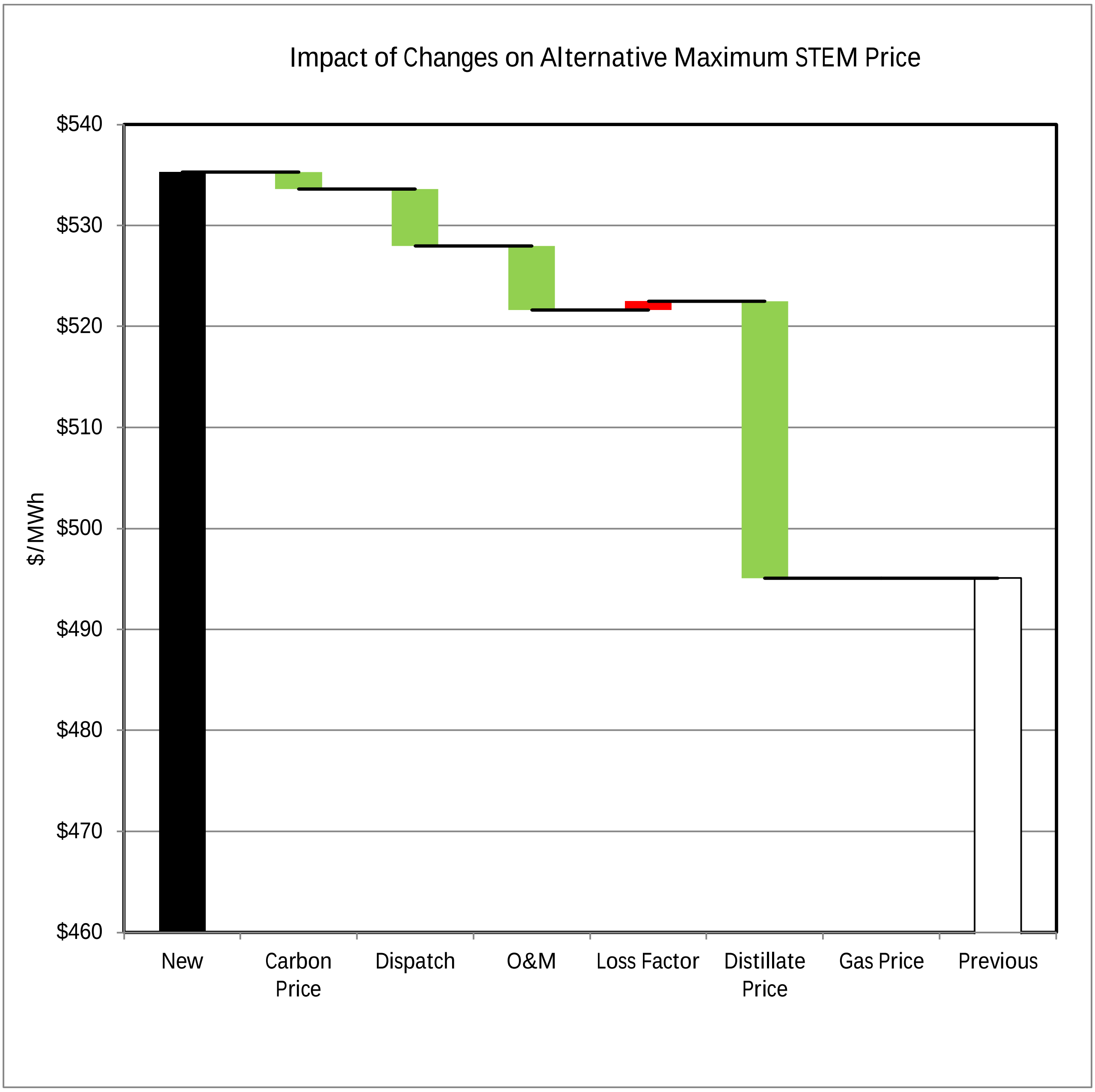
Exec Figure 1 Impact of factors on the change in the Maximum STEM Price since 2013



[4] Rounded to the nearest 10c to avoid implying high precision. Actual unrounded value was $4.69. Values in Table 4-4 rounded.

The increase in the Alternative Maximum STEM Price is primarily due to AUD:US exchange rate changes impacting on the price of distillate and the assessed O&M cost per MWh. The change in assumed dispatch pattern has also had some impact on the O&M cost, as illustrated in Exec Figure 2.

Exec Figure 2 Impact of factors on the change in the Alternative Maximum STEM Price since 2013



It is noted that, while the Alternative Maximum STEM Price is higher than the price that was proposed to apply from July 1 2013 in the 2013 review, it is lower than the price applying in May 2014 which is $566/MWh. The May 2014 price is based on an average Perth Terminal gas price of 148 Ac/litre (Acpl) whereas the equivalent price assumed for this 2014 review is 138.3 Acpl. Applying the proposed Alternative Maximum STEM Price equation, if the higher distillate price of 148 Acpl were assumed, this would result in an Alternative Maximum STEM Price of $580/MWh. Hence, even when assuming the same Perth Terminal gas price, the proposed Alternative Maximum STEM Price is higher due to the exchange rate and dispatch assumption impacts on the assessed O&M cost per MWh.

It is recommended that clause 6.20.7 be reformulated to describe more clearly the use of probability distributions and a choice of a percentile value to derive the Energy Price Limits rather than defining a Risk Margin and adding it to the expected value of the combined distribution of average dispatch cycle cost, or to a function of mean values.

Definitions

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

Term	Explanation
Dispatch cycle cost	This term is used to describe the parameter calculated to determine the Energy Price Limits. It is the total cost of dispatch of a start-up and shut-down cycle of a peaking gas turbine divided by the amount of electrical energy in MWh generated during the dispatch cycle.
Break-even gas price	In simulating the gas price distribution, the delivered gas price was reduced if necessary to make the sampled value of the dispatch cycle cost equal to the dispatch cycle cost for running on distillate, allowing for the impact on relative operating costs and thermal efficiency on both fuels. It was not based on the equivalent heat content of distillate alone.
Carbon price	The previous federal government legislated a carbon pricing mechanism from 1 July 2012 with an initial carbon price of \$23/tCO_2e, a price from 1 July 2013 of \$24.15/ tCO_2e and a price from 1 July 2014 of \$25.40/ tCO_2e. This carbon price has an impact on the cost of production through the purchase cost of emission permits. The current federal government intends to repeal this legislated carbon price by 1 July 2014.
Dispatch cycle	The process of starting a generating plant, synchronising it to the electricity system, loading it up to minimum load as quickly as possible, changing its loading between minimum and maximum levels to meet system loading requirements, running it down to minimum load and then to zero for shutdown.
Energy Price Limits	The Maximum STEM Price and the Alternative Maximum STEM Price as specified in the Market Rules.
Net Ex Terminal Price	Wholesale price for distillate in Perth, Western Australia, after deduction of excise rebate and excluding GST. This price does not include road freight costs.
Margin	The difference between the price caps as set by the IMO and the expected value of the highest short run costs of peaking power.
Market dispatch cycle cost method	A method for calculating the fuel consumption over a dispatch period of a peaking gas turbine that represents various levels of loading consistent with a specified capacity factor. This is an alternative method to specifying a particular heat rate basis irrespective of dispatch conditions.
Market Rules	The rules used to conduct the operation of the Western Australian Wholesale Electricity Market (WEM) as gazetted and amended. The current version of the rules was issued on 1 January 2014 and may be found at http://www.imowa.com.au/rules/wem-rules
Risk Margin	The difference between the price caps as set by the IMO and a function of the expected values of variable O&M costs, heat rate and fuel cost as specified in the Market Rules clause 6.20.7(b). The Risk Margin is intended to allow for the uncertainty faced by the IMO in setting the price caps, or (in the case of the Alternative Maximum STEM price) its fuel and non-fuel price components.
Short run marginal cost (SRMC)	The additional cost of producing one more unit of output from existing plant. In the context of this report it refers to the increase in the total production cost arising from the production of one extra unit of electricity and is measured in dollars per megawatt hour (\$/MWh).
Short run (average) cost	The cost of starting a generating unit, running it to produce electricity for a short period of time (usually less than 12 hours) and then shutting it down divided by the amount of electricity produced during that period of operation. This is measured in \$/MWh.
Short Term Energy Market (STEM)	A day ahead contract market that is operated by the IMO, to allow buyers and sellers of electricity to adjust their contract positions on a day to day basis to allow for variations in demand and plant performance and to reduce exposure to the Balancing Market arising from mismatch between supply (for generators) or demand (for retailers) and their contract position.

Term	Explanation
Jacobs SKM	Sinclair Knight Merz
Synchronisation	Refers to the point in time when a generating unit is connected to the electricity network so that it can be subsequently loaded up to supply power to the electricity system.
Type A gas turbine maintenance	Frequent annual preventative maintenance which may only take a few days and does not require major part replacement. Such maintenance is typically undertaken after 12,000 hours or some 600 unit starts.
Type B gas turbine maintenance	Hot section refurbishment / intermediate overhaul – typically carried out at around 24,000 running hours or 1200 starts. Major thermally stressed operating parts are often replaced.
Type C gas turbine maintenance	Major overhaul of thermally stressed and rotating parts of the gas turbine. Typically undertaken after 48,000 fired hours or 2400 unit starts.
WEM	Wholesale Electricity Market as operated by the IMO.

Important note about your report

The sole purpose of this report and the associated services performed by Sinclair Knight Merz ("Jacobs SKM") is to review the Energy Price Limits to apply in the Wholesale Energy Market for the year commencing 1 July 2014 in accordance with the scope of services set out in the contract between Jacobs SKM and the Client. That scope of services, as described in this report, was developed with the Client.

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

Jacobs SKM derived the data in this report from information sourced from the Client (if any) and/or available in the public domain at the time or times outlined in this report. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report. Jacobs SKM has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

This report should be read in full and no excerpts are to be taken as representative of the findings. No responsibility is accepted by Jacobs SKM for use of any part of this report in any other context.

This report has been prepared on behalf of, and for the exclusive use of, Jacobs SKM's Client, and is subject to, and issued in accordance with, the provisions of the contract between Jacobs SKM and the Client. Jacobs SKM accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party.

1. Introduction

1.1 Review of maximum prices

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

The prices that currently apply are shown below in Table 1-1. Further details are also available on the IMO website: http://www.imowa.com.au/market-reports/price-limits.

Table 1-1 Maximum Prices in the WEM

Variable	Value	From	To
Maximum STEM price	$305.00 / MWh	1 July 2013	1 July 2014
Alternative Maximum STEM Price	$566.00 / MWh	1 May 2014	1 June 2014

Note that the Alternative Maximum STEM Price is adjusted monthly according to changes in the three-monthly average Perth Terminal Gate Price (less excise and GST)[5].

1.2 Engagement of Jacobs SKM

Sinclair Knight Merz (Jacobs SKM) was engaged by the IMO to assist it in:

- reviewing the appropriateness of the Maximum STEM Price and the Alternative Maximum STEM Price, as required under clause 6.20.6 of the Market Rules; and
- proposing values for the Maximum STEM Price and Alternative Maximum STEM Price to apply for the year commencing 1 July 2014.

This Final 2014 Report will be submitted by the IMO to the Economic Regulation Authority (ERA) for approval under clause 2.26 of the Market Rules.

1.3 Basis for review

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

- review the cost basis for the Maximum STEM Price and the Alternative Maximum STEM Price which applies when liquid fuelled generation is required;
- prepare a draft report for public consultation; and
- finalise the report based upon the public consultation.

The Market Rules specify a methodology in clause 6.20.7(b) related to the costs of a 40 MW gas turbine generator without specifying the type of gas turbine technology – for example aero derivative or industrial gas turbine. The key factor is that the costs should represent the “highest cost generating works in the SWIS”. The aero derivative turbines are more flexible in operation, have lower starting costs and generally have higher thermal efficiency. The aero derivative turbines better serve a load following regime and very short peaking duty. The industrial gas turbines are not as well suited to extreme peaking operation and therefore would be expected to be the last units loaded for this purpose, if they were not already running for higher load duty.

[5] The Market Rules require the IMO to use the 0.5% sulphur Gas Oil price as quoted in Singapore, or another suitable price as determined by the IMO.

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

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

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

Where:

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine 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 IMO must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

1.3.1 Analysis in this report

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

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

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

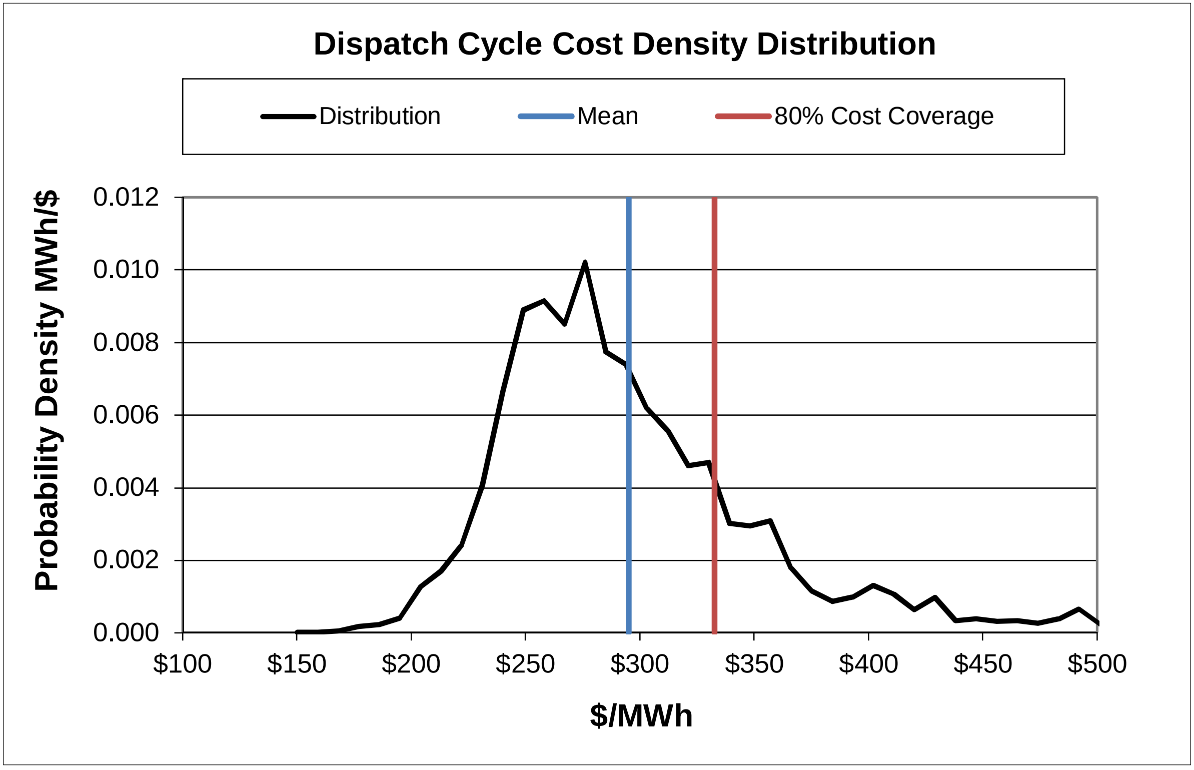
The approach taken to calculate the Risk Margin in this report (as with previous years) is to identify the likely variability in key inputs to the calculation of Energy Price Limits and model the impact that the variability in the key inputs would have on the dispatch cycle cost. This method results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

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

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

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

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



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

1.4 Issues considered in the review

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

1.4.1 Trend in dispatch of gas turbines

An analysis of Pinjar dispatch showed that the frequency of unit starts has decreased by nearly a factor of two since the new high efficiency gas turbines (HEGTs) at Kwinana commenced operation in September 2012. The amount of energy dispatched per cycle also appeared to have reduced. The change in start frequency and energy dispatched per cycle has been reflected in the representation of Pinjar operation for the 2014/15 financial year, as detailed in section 3.3.1.

1.4.2 Movement of distillate road freight to non-fuel component

The distillate road freight remains relatively constant throughout a year and is relatively insensitive to changes in foreign exchange rates. Therefore, this road freight has been removed from the variable fuel component used to calculate the Alternative Maximum STEM Price, and is now included in the non-fuel dependent component when formulating this price.

1.4.3 Distillate price standard deviation

In previous reviews, the standard deviation for distillate has been estimated based on the monthly Brent Crude price variations for the previous calendar year. This year, the standard deviation of the 2013 calendar year daily price variations in the Singapore gasoil price have been used as these are believed to provide a better representation of the variation in Net Ex-Terminal distillate prices.

1.4.4 Changes in methodology for determining spot gas distribution

The spot gas distribution used in this year's analysis has been derived by estimating the impact of the contract price movements on the gasTrading[6] maximum spot price distribution and then allowing some adjustment to cover other short term transactions. A more detailed description of this methodology is provided in Appendix C.

The resulting distribution does not fit a theoretical distribution particularly well, so the discrete input distribution is sampled directly. In the 2013 review, a multi-modal lognormal distribution was fitted to the range of spot gas prices considered.

[6] Gas Trading Australia PL provides services that enable clients to efficiently manage long-term gas supply or purchase contracts. One of these services is a gasTrading operated spot market, a platform that permits clients to buy/sell gas from one another on a short-term basis.

2. Methodology

2.1 Overview

This chapter discusses the price cap methodology as it was applied in this review. Previous IMO reports on the Energy Price Limits, particularly the 2009 review, have thoroughly discussed the evolution of these methods.

2.2 Concepts for Maximum STEM Prices

2.2.1 Basis for magnitude of price

The estimation of the Maximum STEM Price depends on the consideration of a number of factors. Since the purpose of the Maximum STEM Price is primarily to mitigate market power, there are conflicting objectives in setting the Maximum STEM Price, which should be:

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

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

2.2.2 Managing uncertainty

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

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

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

2.2.3 Selection of the candidate OCGT for analysis

The previous analysis of Energy Price Limits has shown that the Pinjar 40 MW gas turbines have the highest cost for short dispatch periods and the Parkeston aero-derivative gas turbines are the next most costly to run for peaking purposes. This has consistently applied since the Energy Price Limits were first determined. In the 2011 review, the Kwinana twin sets were included in the analysis and it was shown that they are very unlikely to have higher dispatch costs than the Pinjar gas turbines, and that they do not need to be considered further. There is no reason to suggest that this would change in the foreseeable future. For these reasons the Pinjar 40 MW machines and Parkeston aero-derivative gas turbines are the two candidate machines selected for analysis in this report. The determination of the highest cost machine is discussed further in section 2.4.

2.3 Determining the Risk Margin

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

- Variable O&M
- Heat Rate
- Fuel Cost
- Loss Factor

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

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

2.3.1 Variable O&M

The determination of Variable O&M costs for the candidate machines is based on engineering data available to Jacobs SKM and the values used in 2011 have been updated to 2014 cost levels. The cost characteristics for the candidate machines are not considered to have changed significantly since 2011 and were therefore not revisited for this review.

These O&M costs are incurred in the following manner:

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

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

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

As in previous years, the characteristics of dispatch cycles experienced by the Pinjar and Parkeston machines were determined through the analysis of historic dispatch data obtained from the IMO. This sampled dispatch data is expressed through the following variables:

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

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

The number of starts per year for Pinjar and Parkeston are based on analysis of historical data from January 2013 to December 2013, covering one full year after the commissioning of the high efficiency gas turbines at Kwinana and the introduction of the Balancing Market. The analysis of the recent dispatch patterns of these units is summarised in section 3.3.1.

2.3.2 Heat rate

The heat rate of the reference machines is based on data provided by the manufacturer as available in heat rate modelling software GT Pro. The heat rate characteristics for run-up and for continuous operation were reviewed and refined in the 2012 review. It is not considered necessary to review these data. The manufacturer data reflects that the actual heat rate of the machine varies with the following:

- Machine load
- Temperature
- Humidity
- Atmospheric pressure.

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

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

The peaking dispatch of the reference machines occurs throughout the year, and therefore the variation of heat rates attributable to temperature variation has been added to the underlying uncertainty. This underlying uncertainty is modelled as having a deviation of 3%[7]. The mean heat rates were interpolated between the above reference temperature values for 25°C corresponding to the mean daily maximum temperature in Perth.

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

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

The "heat rate at minimum capacity approach" is cross checked against a second methodology that establishes the heat rate of the Pinjar machine across the dispatch cycle of the machine and then calculates the aggregate fuel consumption to determine an average heat rate. This approach includes the fuel consumed in start-up and the modelled heat rate for the various load levels as the machine moves through the dispatch cycle, from start-up to shut down. This approach is undertaken with reference to the dispatch cycle method discussed further in section 4.5.1 of this report. This method is not used to determine the recommended Energy Price Limits. Rather, it is used to confirm that the Market Rules can provide Energy Price Limits that reflect the observed pattern of dispatch, and consequently the appropriate heat rate levels.

[7] 3% of the heat rate at 25°C obtained by interpolating with the values at 41°C and 15°C

2.3.3 Fuel cost

This report considers a modelled distribution of likely gas prices to determine the Maximum STEM Price. In addition, Jacobs SKM has chosen to model the carbon emission cost within the Fuel Cost component of the equation. It is recognised, of the options provided in equation 6.20.7(b) of the Market Rules, that the carbon emission cost could be characterised as an O&M cost component. However, as the quantity of carbon emitted is dependent on the heat rate of the machine and is determined by the quantity of fuel consumed, it has been included in the Fuel Cost component of the analysis for simplicity.

Gas cost

The modelling of gas cost is based on additional analysis undertaken by Jacobs SKM and summarised in Appendix C. Jacobs SKM has selected a discrete distribution of gas prices over a predefined range as representative of the underlying spot gas price distribution.

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

Transport cost

The gas transport costs are based on analysis undertaken by Jacobs SKM. These costs have been generally modelled as variable costs [VFTC]. However, for the Parkeston machines, parts of the costs have been treated as fixed costs [FT]. The spot gas transport cost distribution for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) has not changed from the 2013 review.

Daily load factor

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

Carbon cost

The methodology for modelling the carbon cost is to convert this to an equivalent fuel cost based on the specification of the carbon intensity of the WA gas supply using the National Greenhouse Gas Account Factors for gas and distillate as discussed in section 3.5. No variability is modelled in the cost of carbon in this year's report [FER] and [CP].

2.3.4 Loss factor

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

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

For each candidate machine and for each of the variables detailed above a range and a distribution are applied from one of the following options:

- Assume the variable is normally distributed and assign a standard deviation with the base value representing the mean, and then apply maximum and minimum limits if appropriate.

- When specific information is available from the WEM or other sources, Jacobs SKM has analysed the information and derived a suitable probability distribution to represent the uncertainty. This method has been used to analyse run times, generation available capacity and generation capacity factors related to the dispatch cycle.

For each candidate machine, these distributions are used to develop a set of 1000 input combinations to the equation detailed in Appendix B. Based on the distribution of the inputs, this equation is processed for each of this set of inputs to provide a profile of possible costs determining the Energy Price Limits. From this profile a potential Energy Price Limit is selected that covers 80% of the outcomes for that generator.

2.3.6 Risk Margin

To determine the Risk Margin associated with the Energy Price Limit determined through the process described in section 2.3.5 above the following process is adopted. The mean values of the relevant probability distributions described above are used to calculate the term

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

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

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

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

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

2.4 Determination of the highest cost OCGT

Based on the analysis above for Parkeston and Pinjar the unit with the highest Maximum STEM Price is selected. As in previous years the model Pinjar units have been identified as the highest cost machines. To simplify the report the calculations for Pinjar are presented in Chapter 3. The corresponding analysis for Parkeston is provided in Appendix D.

2.5 Alternative Maximum STEM Price

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

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

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

The method for the selection of the non-fuel and the fuel cost factor in the formula for the Alternative Maximum STEM Price was based upon 1,000 samples of each of the two cost factors combined with a range of fixed distillate prices between $15/GJ and $45/GJ, to assess the 80% probability level of cost for each fuel price. Rather than taking the 80% probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80% price versus distillate price. This function is shown with the results in Figure 4.1. This method ensures that the resulting cost is at the 80% probability level over this fuel cost range, given the cost and dispatch related uncertainties.

The non-fuel cost component for the Alternative Maximum STEM Price includes the emission cost as this cost is not dependent on the fuel cost. The elements which make up these cost components are shown in Appendix B.

3. Determination of key parameters

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

3.1 Fuel prices

3.1.1 Gas prices

The analysis of gas prices has been based on the aforementioned additional Jacobs SKM analysis. The recommended approach was to base gas price and transport cost on spot gas trading as in the year from 1 July 2014. The value of gas will be based on the opportunities in the spot gas market for gas that would be used by a 40 MW peaking plant at Pinjar.

3.1.2 Price of gas

The price of gas delivered to a 40 MW power station has two components, the price at the gas producer's plant gate and the cost of transmission from the plant gate to the delivery point at the power station. In this study the gas price has been estimated on the basis that the gas is sourced from the Carnarvon Basin and transported to generators in the South West via the DBNGP.

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

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

These alternative uses have a wide range of values and Jacobs SKM has assessed a range from $7.52/GJ to $11.12/GJ as representing 80% of the range of uncertainty. The methodology and assumptions underpinning this range are discussed in Appendix C.

As described in section 2.3.3 above, a gas price range up to $24/GJ has been modelled with the gas price capped by the comparative value relative to the distillate price[8]. Jacobs SKM has calculated a breakeven gas price for each of the 1000 simulated dispatch cycles given its particular characteristics, including a cost penalty for liquid firing where applicable for industrial gas turbines[9]. The breakeven price was estimated to equalise the dispatch cycle average energy cost. This is preferable to capping the gas price distribution at a single level when estimating the Energy Price Limits.

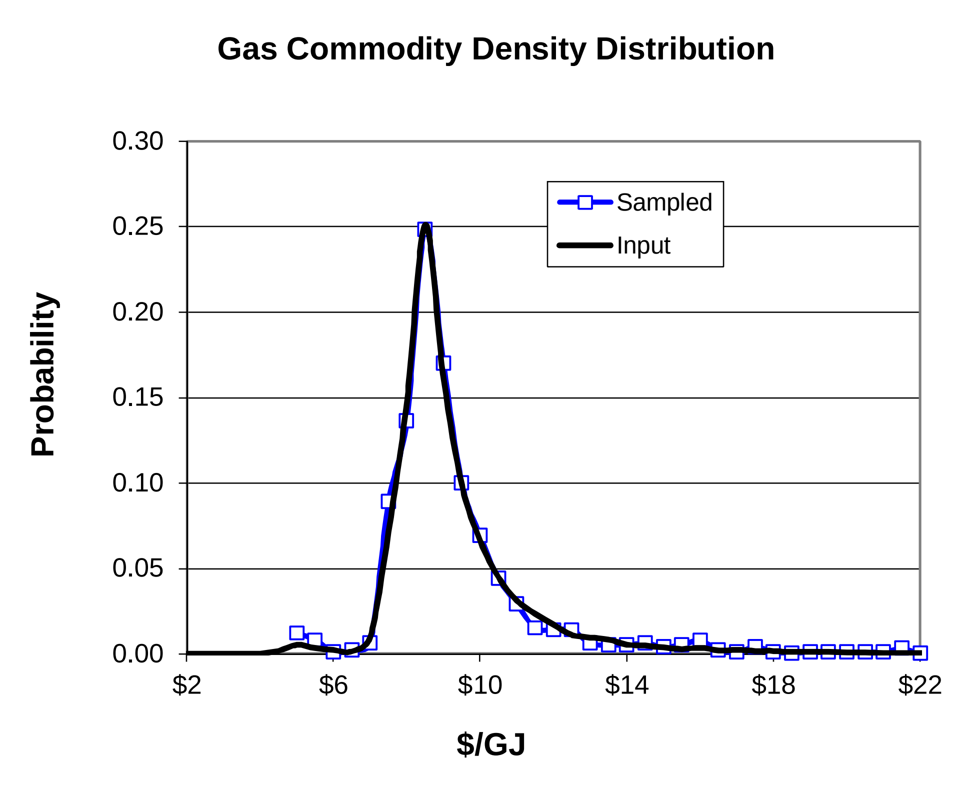
Jacobs SKM has chosen to represent the gas price as a discrete distribution between $2/GJ and $24/GJ, as shown in Figure C- 8 in Appendix C. The mode of the distribution is at $8.50/GJ. In previous years, lognormal distributions have been used to represent the gas spot price distribution, however the assumed price distribution did not fit any theoretical distribution particularly well this year, which is why a discrete distribution has been used.

The resulting gas price distribution as sampled was as shown in Figure 3-1. The smooth black line represents the discrete density function for the gas price from which 1000 samples were drawn.

[8] The distillate price cap is discussed further in section 3.1.6 of this report.
[9] No liquid firing operating cost penalty was applicable to aero-derivative gas turbines which are designed to use liquid fuel.

The sampled gas price did not exceed $21.40/GJ for the industrial gas turbine once capped by the breakeven gas price. Thus modelling the gas price initially to $24/GJ was sufficient. The maximum delivered gas price was $26.13/GJ to the industrial gas turbines.

Figure 3-1 Gas Price distribution as modelled with upper price limited to the distillate equivalent



Note: Gas price excludes the carbon emission cost. The input distribution from which spot gas prices have been sampled is discrete.

3.1.3 Daily load factor

Consistent with the approach adopted for the 2013 review, it has been assumed that, when applied to spot trading on a daily basis, the daily gas load factor is only important to the extent that it represents daily forecast volume error. For that purpose, it is modelled as having an 80% confidence range between 80% and 98% with a 95% most likely value (the mode). The continuous distribution had a mean of 97.0%, but when the maximum value of 1.0 was used to truncate the distribution, the mean value was 89.91%. Jacobs SKM developed the lognormal distribution of Spot Gas Daily Load Factor shown in Figure C- 10. The distribution was truncated and redistributed so that there was no discrete probability of a value of 100%. This was in accordance with the methodology applied in the 2013 review. There is a 0.005% probability of a value at the minimum value 60%.

The effective spot price was calculated by dividing the spot price sampled from the capped distribution in Figure C- 8 by the daily load factor sampled from the capped distribution in Figure C- 10.

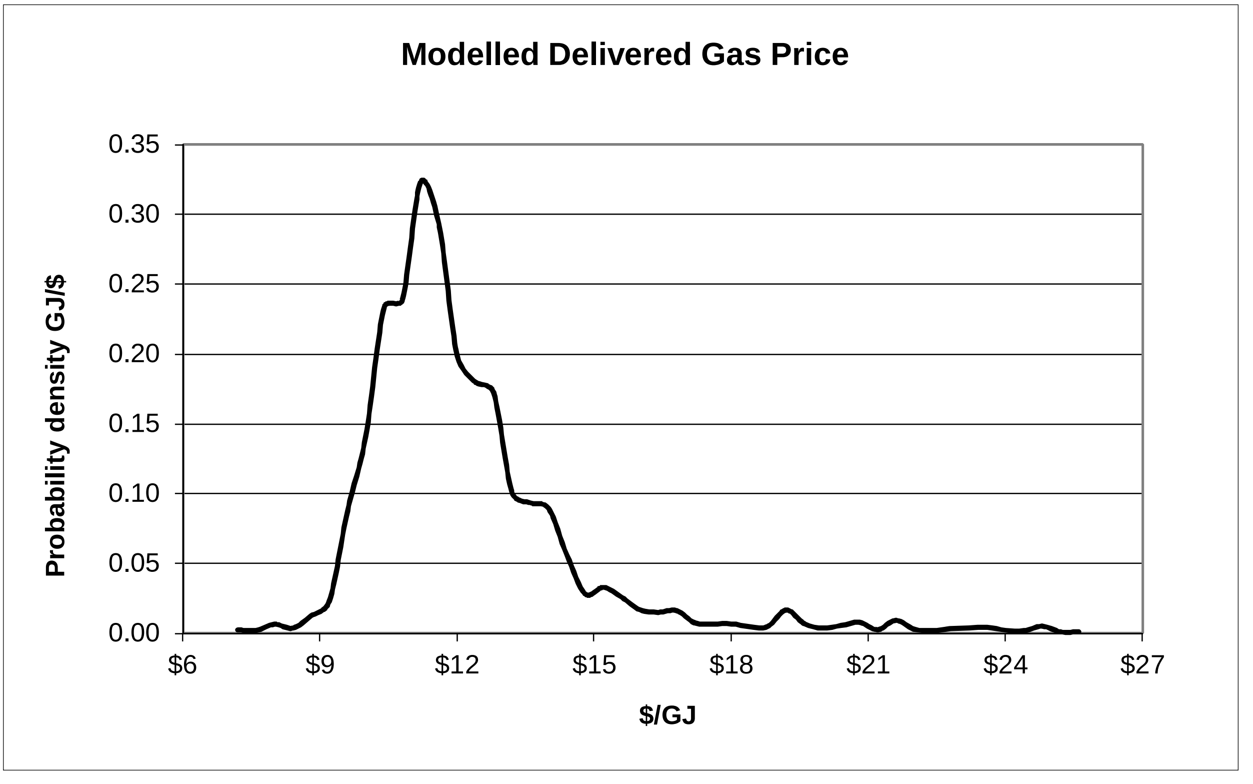
3.1.4 Transmission charges

In previous reviews, ACIL Tasman has recommended basing the gas transport cost on spot market conditions. This same approach has been adopted for this 2014 review. For the transport to Perth, a lognormal distribution is recommended with the 80% confidence range being between $1.46/GJ and $2.15/GJ with a most likely value (mode) of $1.735/GJ. The mean value of the transmission charge is $1.795/GJ. Jacobs SKM developed the distribution shown in Figure C- 9 in Appendix C to represent this uncertainty in the gas transport cost. The gas cost range was taken between $1/GJ and $3/GJ which is consistent with the spreadsheet provided by ACIL Tasman for the 2013 review.

3.1.5 Distribution of delivered gas price

The composite of the variation in the gas supply price, the gas transport price and the daily load factor applied to the gas commodity price results in the probability density for delivered gas price shown in Figure 3-2. The effect of the two skewed distributions is to spread the effect of the capped prices and to result in a range of sampled prices as shown in Table 3-1.

Figure 3-2 Sampled probability density of delivered gas price to Pinjar for peaking purposes



The modelled delivered gas price for the Perth region had an 80% confidence range of $10.10/GJ to $14.56/GJ with a mode of $11.20/GJ and a mean of $12.20/GJ. These values exclude pass on of carbon costs in gas price for supply and transport.

Table 3-1 Modelled delivered gas price distribution to Pinjar

Delivered Gas Prices as Modelled	
	Pinjar
Min	$6.63
5%	$9.74
10%	$10.10
50%	$11.66
Mean	$12.20
Mode	$11.20
80%	$13.30
90%	$14.56
95%	$16.52
Max	$26.13

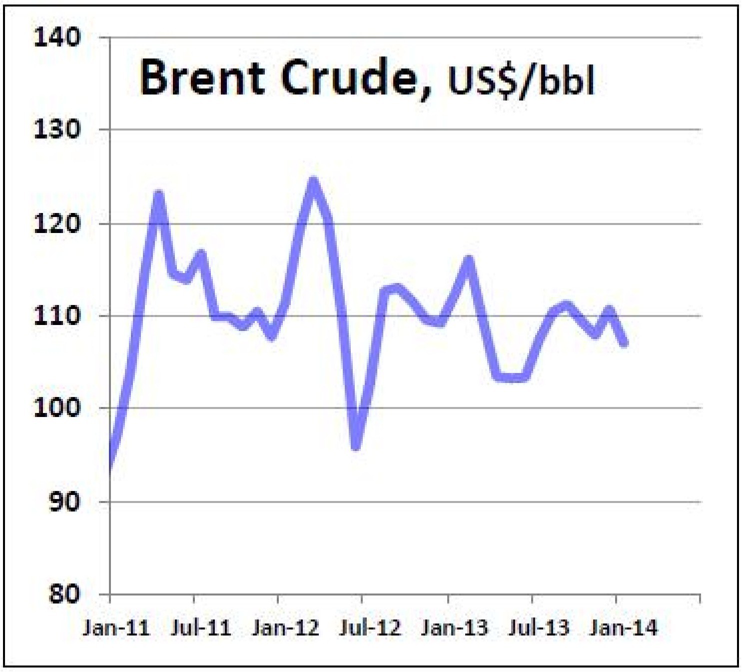
3.1.6 Distillate prices

The Market Rules provide for a monthly re-calculation of the Alternative Maximum STEM Price based on assessment of changes in the Singapore Gas Oil price (0.5% sulphur) or another suitable published price as determined by the IMO[10]. Therefore in this analysis a reference distillate price is assessed to define a benchmark Alternative Maximum STEM Price component that depends on the underlying distillate price.

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

Crude prices were relatively stable through 2013 with Brent crude prices averaging US$108.8/bbl during 2013, slightly lower the historical high of $111.7/bbl during 2012. The month average crude price band[11] in 2013 was $13 while the standard deviation was $3.9, (cf 2012: $29 and $7.6 respectively). However, crude prices remain stubbornly high and have done so for three years.

Figure 3-3 Brent Crude price 2011 to 2014



The volatility of crude prices decreased significantly in 2013 with the absence of any serious geopolitical events. Debt crises were resolved in Europe and the US, China rattled sabres but little else and a nuclear agreement with Iran was reached. The issues in Syria remain a concern for 2014 as do the tensions in the South China Sea, in a year where a number of developing countries are holding elections.

The latest estimate of crude prices from the US Energy Information Agency, EIA, (Dec 2013)1[12] has Brent prices averaging between $92 and $100 in the period 2014 to 2020. In the more recently published short term energy outlook, (12 Feb 2014), the EIA forecast prices averaging US$105/bbl in 2014 and $101/bbl in 2015,

[10] For the last year, IMO has used the Perth Terminal Gate Price (net of GST and excise) for this purpose, as the Singapore Gas Oil price (0.5% sulphur) is no longer widely used. Moreover, the Perth Terminal Gate Price includes shipping costs and so takes into account variations in these costs due to factors such as exchange rate changes.

[11] The range of prices between the minimum and maximum month averaged Brent crude prices

[12] EIA Annual Energy Outlook 2014 Early Release

reflecting increased supplies of crude from non-OPEC members. These numbers imply a price of $103/bbl for Brent in the 2014/15 period. In both publications there is an underlying theme related to increased production of crude from non OECD countries and non-conventional oil.

On the assumption that there is no significant new geopolitical issue, the Brent price expectations during the subject period are estimated at approximately US$100/bbl.

Regionally, the monthly average spot price for Singapore Diesel, (Australian 10 ppm sulphur) was only slightly more volatile than the crude prices, jumping to US$135/bbl in February, dropping back to $118/bbl three months later and then spending the rest of the year in a very narrow band between $123/bbl and $128/bbl. The gasoil to crude spread[13] weakened from $18/bbl in 2012 to an average of $16/bbl for 2013 as anticipated due new refining capacity additions in the region, primarily China. Continued additions to refinery capacity in the region (and the Middle East) will result in added pressures for smaller and less efficient refineries to close over coming years as is evidenced with the ongoing closures of the small Australian refineries.

With additional refinery capacity being streamed, wavering confidence in the Asian (Chinese) economy and bearing in mind the latest EIA forecast, we would assess that the Diesel prices in Singapore for the subject time period will average US$115/bbl. This forecast again assumes that there are no new significant geopolitical events during this period.

The above forecast for the Singapore 10 ppm diesel price of US$115/bbl translates to a wholesale price, (Ex Terminal Price), in Perth, Western Australia of 138.3 Ac/litre, (Acpl). After deducting 38.14 cents excise and GST and applying a heat value of 38.6 MJ/litre, this volumetric cost is equivalent to a Net Ex Terminal price of $22.70/GJ (87.6 Acpl[14]). For comparison, this is based on an AUD/US exchange rate of 0.89.

The road freight for Pinjar and Parkeston is assumed to be 1.43 Acpl and 5.83 Acpl respectively, inclusive of GST ($0.34/GJ and $1.37/GJ net of excise and GST). For the purpose of clause 6.20.7(b) of the Market Rules, this results in a Free into Store, (FIS) price of 139.773 Acpl for Pinjar and 144.173 Acpl for the Parkeston power stations. These volumetric costs are equivalent to $23.04/GJ and $24.07/GJ for the two power stations respectively after deducting 38.14 cents excise and GST and applying a heat value of 38.6 MJ/litre.

It is assumed that Synergy will pay the carbon price assessed in section 3.5 rather than accept the standard excise discount for the carbon price of 6.859 cpl which applies to distillate for power generation. Both methods yield the same Energy Price Limits.

Over the period relevant to the Maximum STEM Price the price of distillate will vary due to fluctuations in world oil prices and refining margins. Based on the recent volatility in daily Singapore gasoil prices (US$4.8/bbl[15]), the distillate price is assumed to have a standard deviation of about 5.25cpl. This translates to $1.36/GJ. This standard deviation is lower than was applied in the 2013 review ($1.94/GJ).

For this review, in capping the gas price the distillate price has been modelled as a normal distribution with a standard deviation of $1.36/GJ. A mean price of $23.04/GJ has been applied in the Perth region for Pinjar.

3.2 Heat rate

3.2.1 Start-up

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

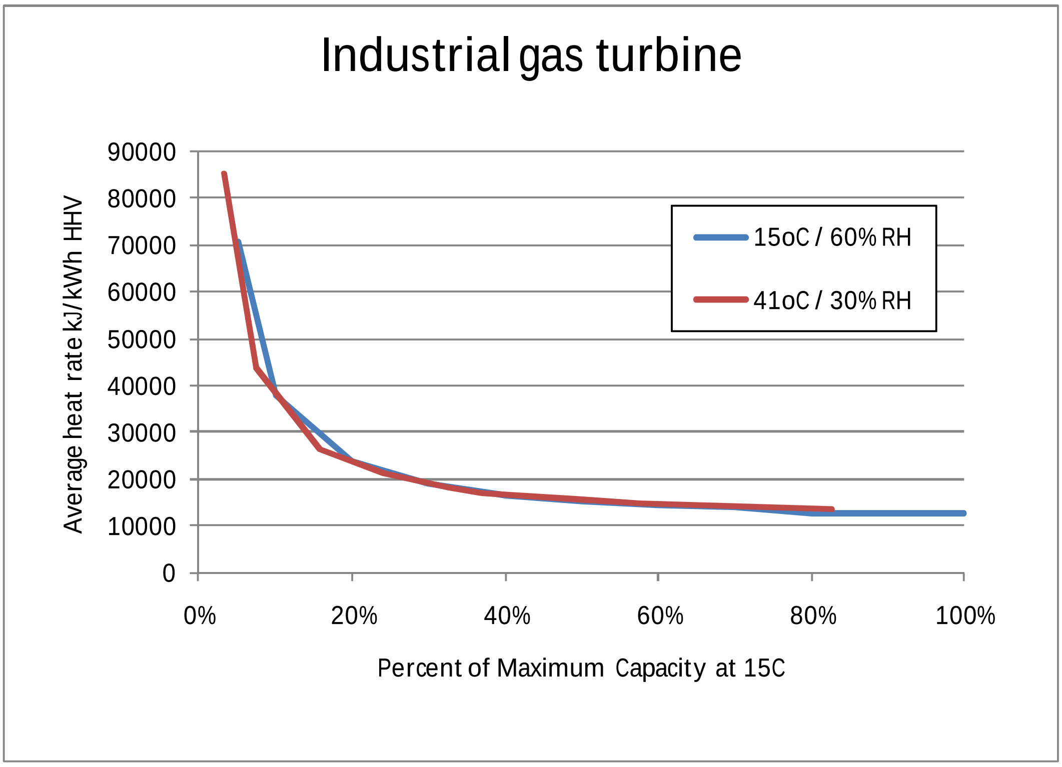
[13] The difference between the gasoil 10ppm price and the Brent crude price

[14] Ex Terminal price is 138.343 Acpl, which is equivalent to $1.258/litre excluding GST. After deducting excise rebate of $0.38143/litre, this results in a Net Ex Terminal price of $0.876/litre.

[15] Standard deviation of daily gasoil prices for the 2013 calendar year. In previous reviews the Brent crude monthly standard deviation had been used, however it is considered more appropriate to use the standard deviation of the Singapore gasoil price since the Singapore gasoil price is what is used to estimate the Ex Terminal price in this analysis.

Figure 3-4 shows the run-up heat rate curve applied for the industrial gas turbine to calculate the energy used to start the machine.

Figure 3-4 Run-up Heat rate curve for industrial gas turbine (new and clean)



3.2.2 Variable heat rate curve for dispatch

Table 3-2 shows the steady state heat rates that were applied for the industrial gas turbine. They were increased by 1.5% to represent typical degradation from new conditions. The temperature sensitivity of the heat rates was estimated from the run-up heat rate curves, and was less than 1% over the range 15°C to 41°C.

Table 3-2 Steady state heat rates for new and clean industrial gas turbines (kJ/kWh HHV)

		% site rating			
Temp	**Humidity**	**100%**	**50%**	**33%**	**25%**
15°C	30%	12990	15843	18711	21438

The minimum load position has been extracted from the sampled data and the corresponding heat rate at minimum determined from Table 3-2. This heat rate at this minimum, including the temperature variability, results in a normal distribution with a mean of 19.153 GJ/MWh sent out and a standard deviation of 1.071 GJ/MWh sent out. The mean has increased slightly and the standard deviation has reduced slightly from the 2013 review due to changes in the assessed level and uncertainty of the minimum operating level based on the analysis of actual dispatch for the Pinjar gas turbines. The change in the assessed minimum operating level changes the average heat rate modelled even though the heat rate characteristics have not been changed since the 2013 review. The average minimum capacity level was decreased slightly in the 2014 review.

3.3 Variable O&M

This section describes the structure of the variable O&M costs for the Pinjar gas turbines. The equivalent data for the less costly aero-derivatives is discussed in Appendix D.

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

3.3.1 Dispatch cycle parameters

The HEGTs commenced operation in September 2012. An examination of the Pinjar dispatch data from September 2012 has shown a halving of the number of starts per month from the average of the last three years from January 2010. This change indicates a change in the role of Pinjar, and that averaging the number of starts over the period from January 2010 is very likely to over-estimate the number of starts per year in the year commencing 2013/14. Jacobs SKM has therefore recommended that the pattern of starts between January 2013 and the end of December 2013 should be used to assess the frequency of starts. By using one complete calendar year of data the approach avoids introduction of seasonal bias, which would have been the case had the full 16 months of data been used since commissioning of the HEGTs.

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

- Pinjar run times have averaged around 12 trading intervals per dispatch cycle. This level is slightly lower than observed in the 2013 review over a longer historical period and reflects a change in dispatch of these units after the introduction of the HEGTs. The average power generation per dispatch cycle has also reduced in the last 12 months when compared against the longer term average.
- Overall the incidence of short run times below 6 hours has been reducing slowly in the Pinjar dispatch since the distributions were first formulated in 2007 and in the updates for the 2009 to 2013 reviews. However, since September 2012, the incidence of short run times below 6 hours has increased. For the 2013 calendar year, approximately 70.5% of all Pinjar run times were below 6 hours, compared to 51.5% observed over the four year period from January 2009.

Number of starts per year

From the operating characteristics of the Pinjar gas turbine machines between January and December 2013, they have been required to do between 31 and 128 starts per year on an individual unit basis, 71.2 starts per year on average, with average run times of between 4.6 and 7.8 hours on a unit basis. This means that the number of starts per year is the primary cost driver, rather than the operating hours.

The number of starts for the six units has a standard deviation of 38.22 starts in a period of one year. This has been represented by a normal distribution up to 3.2 standard deviations from the mean with a minimum number of starts of 10.

The parameters for the modelling of unit start frequency were:

Mean value	71.2 starts/year
Standard deviation	38.22 starts/year
Minimum value	10 starts/year

Run-times

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

The run times of the peaking units have been analysed from the market data from 1 January 2013 to 31 December 2013. A probability density function has been derived which represents the variation in run times. Whilst it would be possible to set a minimum run time of say 1 or 2 trading intervals, this condition occurs very rarely, about 1 in 250 starts for the industrial gas turbines since January 2013[16]. Since other market factors have also been varied, it is preferred to assess the variation of run time as just another uncertain factor rather than treat it as a deterministic variable.

Maximum capacity

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

Dispatch cycle capacity factor versus run-time

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

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

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

The standard deviation of the variation was 11.0% for run times of more than 4 trading intervals and 11.7% for run times of fewer than 4 trading intervals. These values were used to formulate the capacity factor which was then clipped between the practical maximum and minimum values having regard to ramp rates and minimum stable operating capacity levels.

3.3.2 Maintenance costs

Jacobs SKM has not been able to source any later information than that obtained in 2011 for maintenance costs. The costs are shown in Table 3-3 in December 2014 dollars for General Electric Frame 6 gas turbines with the maintenance stage occurring after the stated number of running hours or the stated number of starts, whichever comes first. In the maintenance cycle there are two, Type A overhauls, one of Type B and one Type C at the end. The costs were originally provided in March 2011 $US dollars. They were converted to Australian dollars at the rate ($AUD = $US0.89) and were then escalated to December 2013 Australian dollars based on Australian CPI and then further escalated by 12 months at 2.5% pa escalation to bring them up to estimated December 2014 dollars.

It should be noted that the Type B overhaul is more expensive than the Type C overhaul because spare parts are purchased for the Type B overhaul to replace parts which are then refurbished for the Type C overhaul, which is therefore less expensive because parts have been reused.

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

Table 3-3 Overhaul costs for industrial gas turbines (December 2014 dollars)

Overhaul Type	Number of hours trigger point for overhaul	Number of starts trigger point for overhaul	2014 Cost per overhaul	Number in each overhaul cycle	Cost
A	12000	600	$1,053,880	2	$2,107,760
B	24000	1200	$4,451,208	1	$4,451,208
C	48000	2400	$1,747,511	1	$1,747,511
					$8,306,479

No adjustment is applied for any future changes in foreign exchange rates. Each maintenance cycle of 2400 units starts and ends with a Type C overhaul.

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

- the average running hour cost is $8,306,479 / 48,000 = $173.05/hour = $4.54/MWh at full rated output (38.081 MW)[17]
- the average start cost is $8,306,479 / 2400 = $3,461/start
- one start is equivalent to 20 running hours, but (in the G.E. methodology) they are not interchangeable, as an overhaul is indicated either by the starts criterion or the hours-run criterion, rather than a mixture of the two.

However, these costs are spread over several years and it is not appropriate to divide these costs by the number of starts or number of running hours to derive an equivalent cost accrual.

To account for the fact that the maintenance costs in Table 3-3 are distributed over several years and that it is not public knowledge when each unit has been maintained and where it is in its long-term maintenance cycle, Jacobs SKM has assumed an average point in time across the maintenance cycle and that all future maintenance is spread over a remaining 20 year life.

For each cycle Jacobs SKM has calculated a discount factor on the future maintenance cost as:

1/Log(1+DR)*(1-(1+DR)^(- CL/SPY))*SPY/CL

Where:

DR is the discount rate taken to be 9% per annum (pre-tax real);

CL is the maintenance cycle length at 2400 starts;

SPY is the average number of starts per year at 71.2; and

Log is the natural logarithm.

The formula is derived from the integral of the present value function of the future maintenance costs over the range of time from zero to CL/SPY years.

PV(t) = X / (1 + DR) ^ t

Where:

X is the maintenance expenditure at future time t with real discount rate DR; and

[17] Calculation based on rate of output for a new machine at 15ºC, 60% relative humidity. The O&M cost is calculated based on a sampled capacity derived from market dispatch data in the Energy Price Limits cost model.

PV(t) is the present value of the future maintenance expenditure in year (t).

PV(t) is integrated with respect to (t) over the range 0 to CL/SPY and multiplied by SPY/CL to obtain an expected present value given that (t) is unknown and assumed to be uniformly distributed over the maintenance cycle.

Thus the total cost is:

X/Log(1+DR)*(1-(1+DR)^(- CL/SPY))*SPY/CL

The scaling factor is a function of the discount rate and the average number of starts per year. A lower number of starts effectively increase the discounting of future maintenance costs per start because it has the effect of delaying the subsequent scheduled overhauls to later years.

Table 3-4 shows an assessment for industrial gas turbine at 71.2 starts per year. The table shows the various scheduled maintenance stages, the corresponding cost and discounted cost as well as a 20% allowance for additional unscheduled maintenance that would arise from normal peaking operations.

Table 3-4 Assessment at 71.2 starts/year (historical dispatch from January 2013)[18]

Overhaul type	Number of starts trigger point for overhaul	Cost per overhaul	Number in an overhaul cycle	Cost	Average discounted cost
A	600	$1,053,880	1	$1,053,880	$342,815
B	1200	$4,451,208	1	$4,451,208	$1,447,928
A	1800	$1,053,880	1	$1,053,880	$342,815
C	2400	$1,747,511	1	$1,747,511	$568,446
Discounted Cost per start		$1,126		$8,306,479	$2,702,005
Total Scheduled Cost		$1,126			
Unscheduled Cost Ratio		20%			
Total Cost		$1,351	**Based on**	**71.2**	**Starts / year**

The start-up cost at 71.2 starts per year is now $1,351/start, compared with the value of $1,204/start in the 2013 review. The increase in discounted start cost is due to the reduction in the value of the Australian dollar against the US dollar, from $AUD = $US1.03 in the 2013 review to $AUD = $US0.89 in this review.

For the calendar year 2013 average historical MWh production per start (including dispatch cycles greater than 6 hours) of 99.5 MWh, the equivalent variable (non-fuel) O&M cost derived from the discounted start cost of $1,351 is $13.58/MWh compared to $10.02/MWh in the 2013 review.

In the simulation of variable O&M cost Jacobs SKM has taken the start-up cost based on the average number of starts per year, that is with 71.2 starts per year with a standard deviation of 54% of that value (38.2 starts/year on an annual basis) based on the observed variability of the number of starts per year across the units.

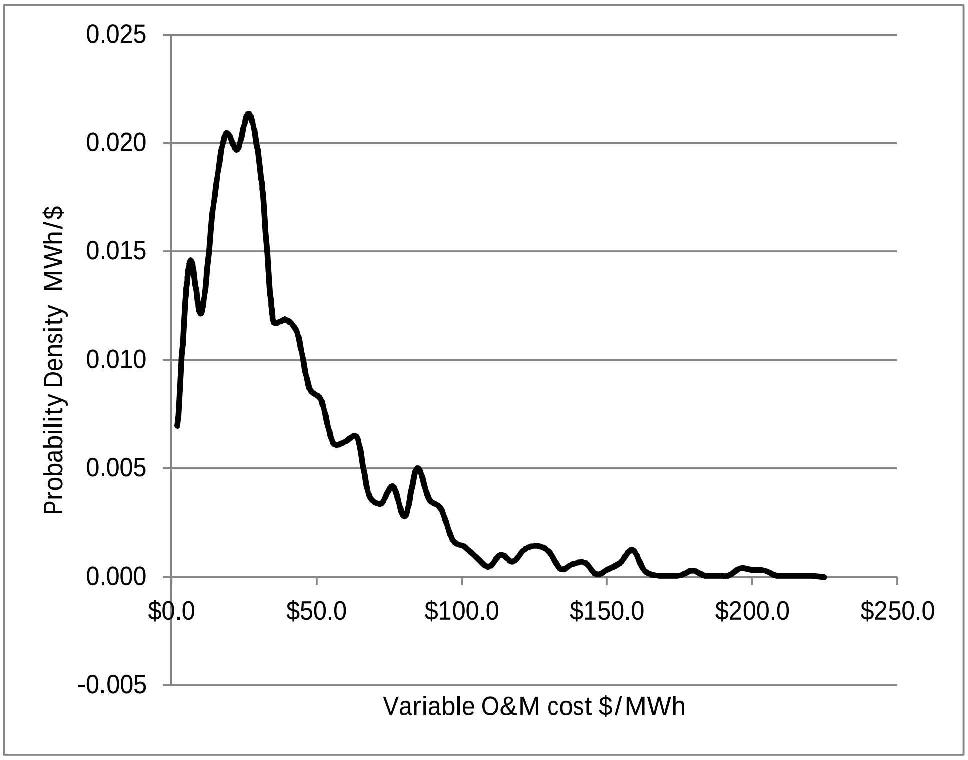
The formulation of the capacity, run-times and capacity factors is shown in Appendix B.

[18] Values in Table 3-4 do not add due to rounding.

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

For the sampled generation levels up to 6 hours based on the historical dispatch, the average variable O&M value is $42.27 MWh before the application of the loss factor. The resulting distribution which provides this mean value is shown in Figure 3-5.

Figure 3-5 Probability density of variable O&M for industrial gas turbine (excluding impact of loss factor)



Based on the start cost of $1,351, the average variable O&M of $42.27/MWh corresponds to an equivalent generation volume per cycle of 31.97 MWh, equivalent to about one hour running at 80% load factor or 2 to 3 hours at minimum load. It is these short dispatch cycles which are covered by the resulting Energy Price Limits.

Table 3-5 shows the characteristics of these distributions before loss factor is applied.

Table 3-5 Parameters of variable O&M cost distributions (before loss factor adjustment)

Pinjar variable O&M	$/MWh
90% POE	$10.25
Mean	$42.27
10% POE	$85.84
Minimum	$2.05
Median	$31.43
Maximum	$272.05
Standard Deviation	$36.20

The analysis detailed above for the historical dispatch results in an average variable O&M cost of $42.27/MWh with an 80% confidence range as sampled between $10.25/MWh and $85.84/MWh, excluding the impact of loss factors.

3.4 Transmission marginal loss factors

The transmission loss factors applied were as published for the 2013/14 financial year for sites where aero derivative gas turbines and industrial gas turbines of 40 MW capacity are installed. The loss factor for Pinjar for the 2013/14 financial year is 1.0312.

The loss factors will not be available until near the beginning of the financial year, so it is expected that the IMO will need to make last minute adjustments. The loss factor for Pinjar for 2013/14 has been applied in this analysis. Parameters should be scaled directly for any change in the Pinjar loss factor published for 2014/15[19]. Since a higher loss factor reduces the Energy Price Limits, the relationship is mathematically inverse, that is a 1% increase in the loss factor would reduce the Energy Price Limits by 1-1/(1+1%) = -0.99%.

3.5 Carbon price

From 1 July 2014, the carbon price is legislated to increase from \$24.15/tCO_2e to \$25.40/tCO_2e. The pricing of carbon emissions adds to the effective dispatch cost of peaking generation through the emissions associated with the consumption of fuel for start-up and operation. In terms of clause 6.20.7(b), this could be regarded as a component of the Variable O&M cost. However, as the emission cost is a result of burning the fuel and the cost is influenced by the heat rate, we consider it more useful to include this cost as part of the fuel cost in \$/GJ. The emissions associated with the start-up fuel consumption are also included as part of the fuel cost.

For information, Jacobs SKM has also calculated the Energy Price Limits for the 2014/15 financial year without a carbon price, as presented in Appendix F.

When the carbon price is applied to the emissions from the power station, there will be impacts arising from the combustion and fugitive carbon emissions associated with burning the fuel. Gas and distillate have different emission intensities. Therefore there will be a separate impact for each fuel. Jacobs SKM has made the following assumptions:

1) The carbon price to apply from 1 July 2014 will be \$25.40/tCO_2e and it will apply for the whole financial year.
2) The dispatch of the gas fired peaking plants will not be materially influenced by the carbon price. This assumption may become incorrect as carbon price increases further. It is expected to be a robust assumption in 2014/15 as the carbon price, if continued, is not expected to be great enough to change the role of the 40 MW gas turbines considered in this review. The market dispatch data did not show any obvious change in dispatch patterns for the Pinjar and Parkeston peaking plants when the carbon price was introduced.

For gas and distillate supplied to the peaking generators, there will be carbon emissions associated with:

1) The production of the fuel
2) The transport of the fuel
3) The combustion of the fuel

These components are discussed for each fuel in the following sub-sections. The parameters used are taken from “National Greenhouse Accounts (NGA) Factors” dated July 2013. The allowance for emissions associated with the production of gas and distillate are less clear from the user’s perspective and it is likely that they would be reflected in the price of the product itself ultimately. Jacobs SKM has estimated a contribution of approximately 10c/GJ for the production and transport components as discussed in the following section. The split between the contributions from gas production and gas pipeline operation have been estimated to determine differing allowances for the Dampier to Bunbury Pipeline (DBNGP) and the Gas to the Goldfields Pipeline (GGP).

[19] The change in loss factor from 2012/13 to 2013/14 was 0.165% which had no material effect on the assessed Energy Price Limits.

3.5.1 Gas fired generation

The emission rate for combustion of natural gas is assessed as 51.33 kg CO_2e/GJ from Table 2 of the National Greenhouse Accounts (NGA) Factors[20].

The emissions of carbon dioxide from the production and transmission of carbon dioxide are shown in "Table 37: Scope 3 emission factors – natural gas for a product that is not ethane (inclusive of coal seam gas)" of the NGA Factors. It shows 4.0 kg CO_2e/GJ for the metro area and 3.9 kg CO_2e/GJ for non-metro areas. This emission rate converts to 10.16c/GJ and 9.91c/GJ respectively at \$25.40/tCO_2e. Comparison with an estimate of the transportation cost confirms this basis as follows.

The actual emissions for transport of natural gas depend principally upon the amount of energy used for compression, which varies with pipeline design and load and has a generally linear relationship with distance transported. Emissions calculations use a standardised linear distance relationship. The relevant transmission factor is 8.72 t CO_2-e /km of pipeline[21]. The total emission of the Dampier to Bunbury Pipeline (DBNGP) is published in the NGERS Greenhouse and Energy Information for 2011/12[22] as 255,716 t CO_2-e. The average throughput of the pipeline in calendar year 2012 was projected by DBP to be approximately 651[23] TJ/day which gives an annual value of 238 PJ. Dividing the published emissions into the throughput gives a transport emission of 1.076 kg CO_2-e/GJ, (assuming that the calendar year throughput estimate was similar to the throughput for 2011/12)[24]. This corresponds to 2.7c/GJ in 2014/15, as shown in Table 3-6.

Table 3-6 Analysis of gas transport emissions

	Units	DBNGP
Energy Consumption	TJ	4,744
Gas Combustion	t CO_2-e	243,517
Pipeline	t CO_2-e	12,199
Total	t CO_2-e	255,716
NGER Emissions	t CO_2-e	255,716
Transported	TJ	237,615
	TJ/day	651
Emissions	kg CO_2-e /GJ	1.076
c/GJ @ \$25.40/tCO2e		2.7

Jacobs SKM has adopted an overall Scope 3 emission rate of 4 kg CO_2e/GJ for the Pinjar power station. Assuming that 1.076 kg CO_2e/GJ represents gas transport emissions; this leaves 2.92 kg CO_2e/GJ for emissions from gas production. The total emission factor for gas is therefore 55.33 kg CO_2e/GJ for Pinjar, including emissions from gas production, transport and combustion in the power station. The emission cost is then added to the simulated fuel cost at the carbon price of \$25.40/tCO_2e.

[20] National Greenhouse Accounts Factors July 2013, Department of Climate Change and Energy Efficiency, Table 2, page 14
[21] Table 15: Natural gas transmission emission factors, NGA Factors.
[22] http://www.cleanenergyregulator.gov.au/National-Greenhouse-and-Energy-Reporting/published-information/greenhouse-and-energy-information/Greenhouse-and-Energy-information-2011-2012/Pages/default.aspx
[23] DBNGP Capacity Register September 2012
[24] This emission intensity is slightly higher than the intensity assumed in the Margin Value review for 2014/15. The Margin Value review assumed an average daily throughput of 748TJ/day based on ERA values reported in http://www.erawa.com.au/3/1086/48/dampier_to_bunbury_natural_gas_pipeline__revised_a.pm. The DBP projections, being more recent, are assumed to be a closer representation of actual throughput in the 2011/12 financial year.

3.5.2 Distillate fired generation

The combustion of distillate (described as diesel oil for stationary energy purposes) is assessed as 69.5 kg CO_2e/GJ from Table 3 of the NGA Factors[25].

For distillate supplied to these peaking plants, the notional allowance for transport of distillate is 5.3 kg CO_2e/GJ[26]. However, there is no legislation yet in place to levy this carbon impost on heavy transport and this is not likely before 1 July 2014 given the current federal government's intention to repeal the carbon price. We therefore apply a total emission of 69.5 kg CO_2e/GJ to represent the likely emission intensity of delivered distillate for power stations.

[25] National Greenhouse Accounts Factors July 2013, Department of Climate Change and Energy Efficiency, Diesel oil in Table 3, Page 16: 69.5 = 69.2 + 0.1 + 0.2 for the individual components

[26] Ibid Table 39, Page 71.

4. Results

4.1 Maximum STEM Price

The dispatch cycle costs of the dispatch of the industrial gas turbines are projected as shown in Table 4.1 using the average heat rate at minimum operating capacity.

Table 4.1 Analysis of Industrial gas turbine dispatch cycle cost using average heat rate at minimum capacity

	Pinjar Gas Turbines	
	Gas	**Distillate**
Mean	$295.14	$505.65
80% Percentile	$332.46	$539.89
90% Percentile	$343.23	$574.61
10% Percentile	$236.74	$447.09
Median	$282.48	$501.09
Maximum	$541.05	$766.20
Minimum	$155.16	$388.32
Standard Deviation	$58.39	$50.93
Non-fuel component $/MWh		
Mean		$80.38
80% Percentile		$92.78
Fuel component GJ/MWh		
Mean		18.734
80% Percentile		19.494
Equivalent fuel cost for % value ($/GJ)		
Mean		$22.700
80% Percentile		$22.936

The Maximum STEM Price is based on 80% probability that the assessed cost would not be exceeded for run time events of 6 hours or less. Using the average heat rate at the minimum capacity the Maximum STEM Price would yield a value of $332/MWh[27].

4.1.1 Coverage

It must be recognised that only short run times from 0.5 to 6 hours have been applied in formulating the distributions. This arrangement therefore covers a high proportion of dispatch cycles represented in the analysis, as shown in Table 4-2 which shows the results of a calculation which estimates the proportion of dispatch events that would be expected to be covered by the Maximum STEM Price.

Taking into account the distribution of run-times, it is estimated that at least 85% of gas fired run-time events would have a dispatch cycle cost less than the proposed Maximum STEM Price, based on the mathematical representation of uncertainties included in this analysis and using historical dispatch characteristics.

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

Table 4-2 Coverage of Maximum STEM Price for Pinjar

Dispatch	Historical from Jan 13 (80 percentile)
Proportion of dispatch cycles less than 6 hours	70.3%
Proportion of 6 hourly dispatch cycles covered by Maximum STEM Price (by simulation)	79.8%
Proportion of dispatch cycles covered by Maximum STEM Price	85.8%

4.2 Alternative Maximum STEM Price

The Alternative Maximum STEM Price is varied each month according to changes in the price of distillate. It is therefore necessary to separate out the cost components that depend on fuel cost and those which are independent of fuel cost. Accordingly, the lower half of Table 4.1 presents the non-fuel and fuel components of the Alternative Maximum STEM Price for the distillate firing of the gas turbines, as well as parameters of the fuel price as simulated[28]. The road freight cost of distillate is not included in the fuel component as it is considered that this price is largely independent of the price of distillate. This is a change from previous Energy Price Limit reviews.

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

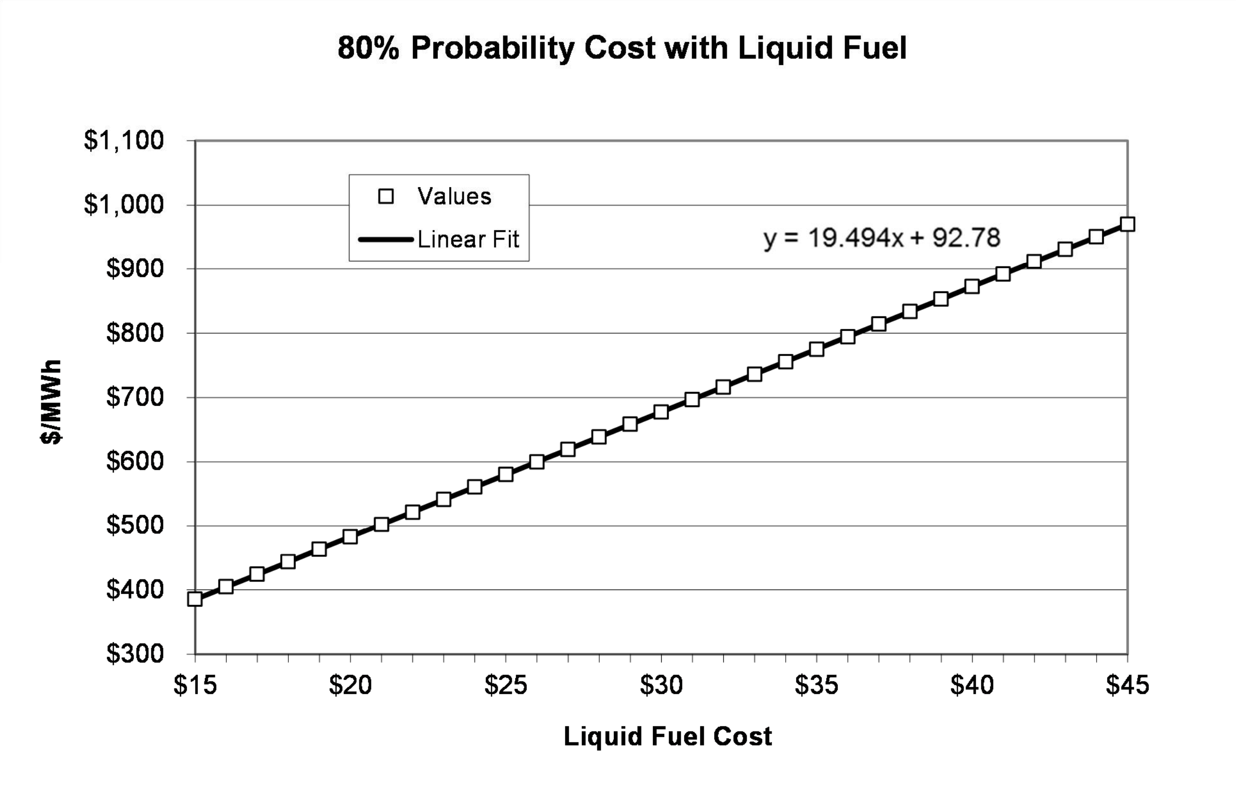
$92.78/MWh + 19.494 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

As discussed in Section 2.5, the method for selection of the non-fuel and fuel cost factors in the above formula was based upon 1,000 samples of each of the two cost factors combined with a range of fixed distillate prices between $15/GJ and $45/GJ, to assess the 80% probability level of cost for each fuel price. Rather than taking the 80% probability values of the cost terms themselves, the two cost factors were derived from the linear regression fit of the 80% price versus distillate price. This function is shown in Figure 4.1.

Assuming a Net Ex Terminal distillate price of $22.70/GJ, we calculate a cap price of $535.00/MWh using the Alternative Maximum STEM Price equation above. This value is based on 80% probability that the assessed cost would not be exceeded for run time events of 6 hours or less and is based on the industrial type gas turbine. The 80% simulated value in Table 4.1 of $539.89 has been calculated by modelling the uncertainty in distillate price in the simulations. This value is slightly higher than the value obtained with a fixed fuel price.

[28] The percentile values of the fuel and non-fuel components shown in Table 4.1are provided for calculating the Alternative Maximum STEM Price. They are not the percentile values of the sampled parameters themselves. For example the 80% value of the non-fuel component in the 1000 samples was $99.44/MWh and the fuel component 80% value was 20.033 GJ/MWh for the industrial gas turbine. These are not the same values shown in Table 4.1 ($92.78/MWh and 19.491 GJ/MWh respectively) which used together calculate the 80% value of the Alternative Maximum STEM Price.

Figure 4.1 80% Probability generation cost with liquid fuel versus fuel cost (using average heat rate at minimum capacity)



4.3 Price components

The Market Rules specify the components that are used to calculate the Energy Price Limits and these have been applied in a statistical simulation. Table 4-3 summarises the expected values of the various components and the Risk Margin values that are required under paragraphs (i) to (v) of clause 6.20.7(b) so that the resulting calculation will provide the assessed Energy Price Limits.

It shows:

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

It should be noted that the mean and 80 percentile values for the Energy Price Limits cannot be calculated by using the corresponding mean and percentile values for the individual components due to the asymmetry of the probability distributions of the cost components. It may be noted that the “Before Risk Margin” in Table 4-3 is significantly higher than the expected value of the dispatch cycle cost due to these asymmetries.

4.4 Sources of change in the Energy Price Limits

To illustrate the sources of change in the Energy Price Limits, a series of studies was developed with progressive changes in the input parameters from the current parameters to those which were applied in the 2013 review of Energy Price Limits. In each case the 1000 simulations were conducted with the same sets of random inputs except where distribution parameters were changed. In such cases, the 1000 sampled input values were taken from the analysis used in the 2013 Energy Price Limits review. This ensures that the impact of random sampling error on the assessed changes is minimised. The value of the dispatch cycle cost was taken which exceeded 800 (80%) of the 1000 samples.

Table 4-3 Illustration of components of Energy Price Limits based on mean values

Component	Units	Maximum STEM Price	Alternative Maximum STEM Price	Source
Mean Variable O&M	$/MWh	$42.27	$42.27	Mean of Figure 3-5
Mean Heat Rate	GJ/MWh	19.267	19.319	Mean AHRN plus start-up fuel consumption.[29]
Mean Fuel Cost (+ CO2e cost)	$/GJ	$13.60	$24.81	Mean of Figure 3-2 for delivered gas price distribution plus emission cost.
Loss Factor		1.0312	1.0312	Western Power Networks
Before Risk Margin 6.20.7(b) 30	$/MWh	$295.09	$505.79	Method 6.20.7(b)
Risk Margin	$/MWh	$36.91	$29.21	By difference from Energy Price Limits
	%	12.5%	5.8%	By ratio
Assessed Maximum Price	$/MWh	$332.00	$535.00	Energy Price Limit calculation

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

1) The 2014 review case
2) The 2012/13 Carbon price of $24.15/tCO_2e applied
3) Previous dispatch patterns restored
4) Previous operating and maintenance costs restored
5) Previous loss factor applied
6) Previous distillate cost and standard deviation applied. Road freight moved back to being part of the variation fuel component
7) Previous gas commodity cost distribution applied
8) The calculation of the 2013 Maximum STEM Price based on the 80% probability of coverage of the dispatch cycle cost.

4.4.1 Change in the Maximum STEM Price

Table 4-4 provides an analysis of the specific changes to show the changes in the Maximum STEM Price and the parameters affected as described in Appendix B. The table describes the successive changes made to the 2014 analysis to convert it back to the 2013 analysis.

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

Table 4-4 Analysis of changes to form the waterfall diagram for the Maximum STEM Price

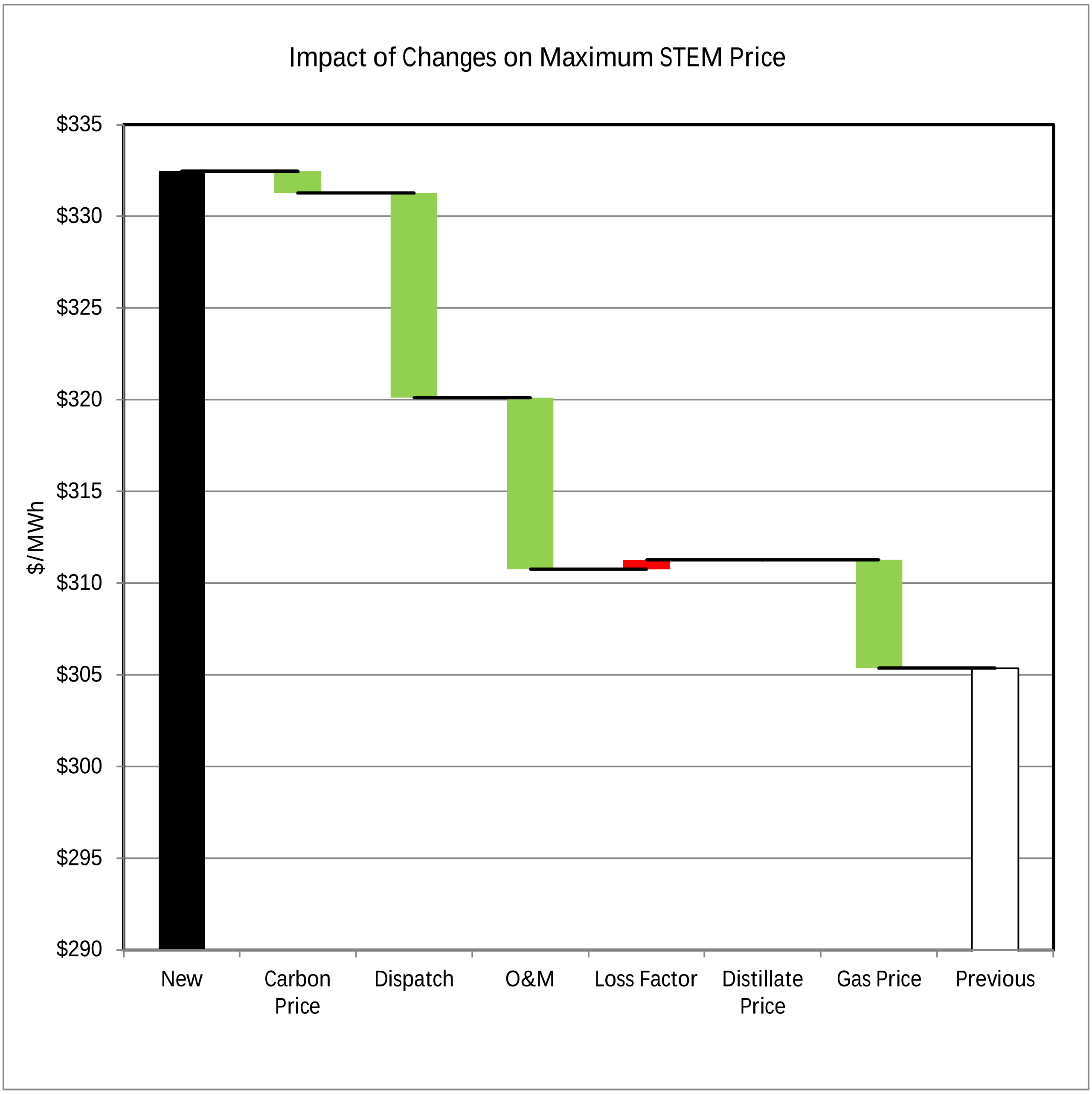
Step	Label in chart	Changes	Parameters affected (Appendix B)
1	New	The basis for the 2014 Energy Price Limits	
2	Carbon Price	Apply the 2013/14 carbon price of $24.15/tCO2e to Case 1	CP
3	New Historical Dispatch Patterns	Capacity, run-times and dispatch cycle capacity factor based on the data from 1 January 2009 to 31 January 2013, with adjustment post August 2012, replaces the data from 1 January 2013 to 31 December 2013.	CAP, CF, RH, and hence MPR
4	O&M Parameters	The O&M costs for the industrial gas turbines were replaced with the 2013 values (reversing CPI and exchange rate adjustments).	VHC, SUC
5	Loss Factor	Restore loss factor to 2012/13	LF
6	Distillate Price	Distillate price was changed from $23.56/GJ to $21.65/GJ, the road freight was moved back to the variable fuel component of the calculation, and the 2012/13 standard deviation was restored	VFC for distillate (gas price cap altered for Maximum STEM Price)
7	Gas Price	The spot gas commodity cost distribution was replaced with the distribution that applied in the 2012 review.	VFC (gas)
8	Old	The calculation of the Maximum STEM Price based on the 2013 parameters.	

Figure 4-2 and Table 4-5 show the relative contribution of the various changes to the Maximum STEM Price since the 2013 review. The major changes have been caused by the change in AUD:US exchange rate, which has increased the O&M cost per unit dispatch. The change in the spot gas price distribution also resulted in a slight increase in the Maximum STEM Price, in the order of $5.90/GJ. The relative contributions to the change in the Maximum STEM Price are illustrated in the waterfall diagram in Figure 4-2.

Table 4-5 Impact of factors on the change in the Maximum STEM Price

Factor	Impact $/MWh
Carbon Price	$1.18
Dispatch	$11.15
O&M	$9.35
Loss Factor	-$0.51
Distillate Price	$0.00
Gas Price	$5.91

Figure 4-2 Impact of factors on the change in the Maximum STEM Price



4.4.2 Change in Alternative Maximum STEM Price

Table 4-6 provides an analysis of the specific changes to show the changes in the Alternative Maximum STEM Price and the parameters affected as described in Appendix B. The table describes the successive changes made to the 2014 analysis to convert it back to the 2013 analysis.

Figure 4-3 and Table 4-7 show the relative contribution of the various changes to the Alternative Maximum STEM Price since the 2013 review. The major changes have been caused by the reduced operation of Pinjar, the impact of the reduction AUD:US exchange rate on O&M costs, and the higher distillate price.

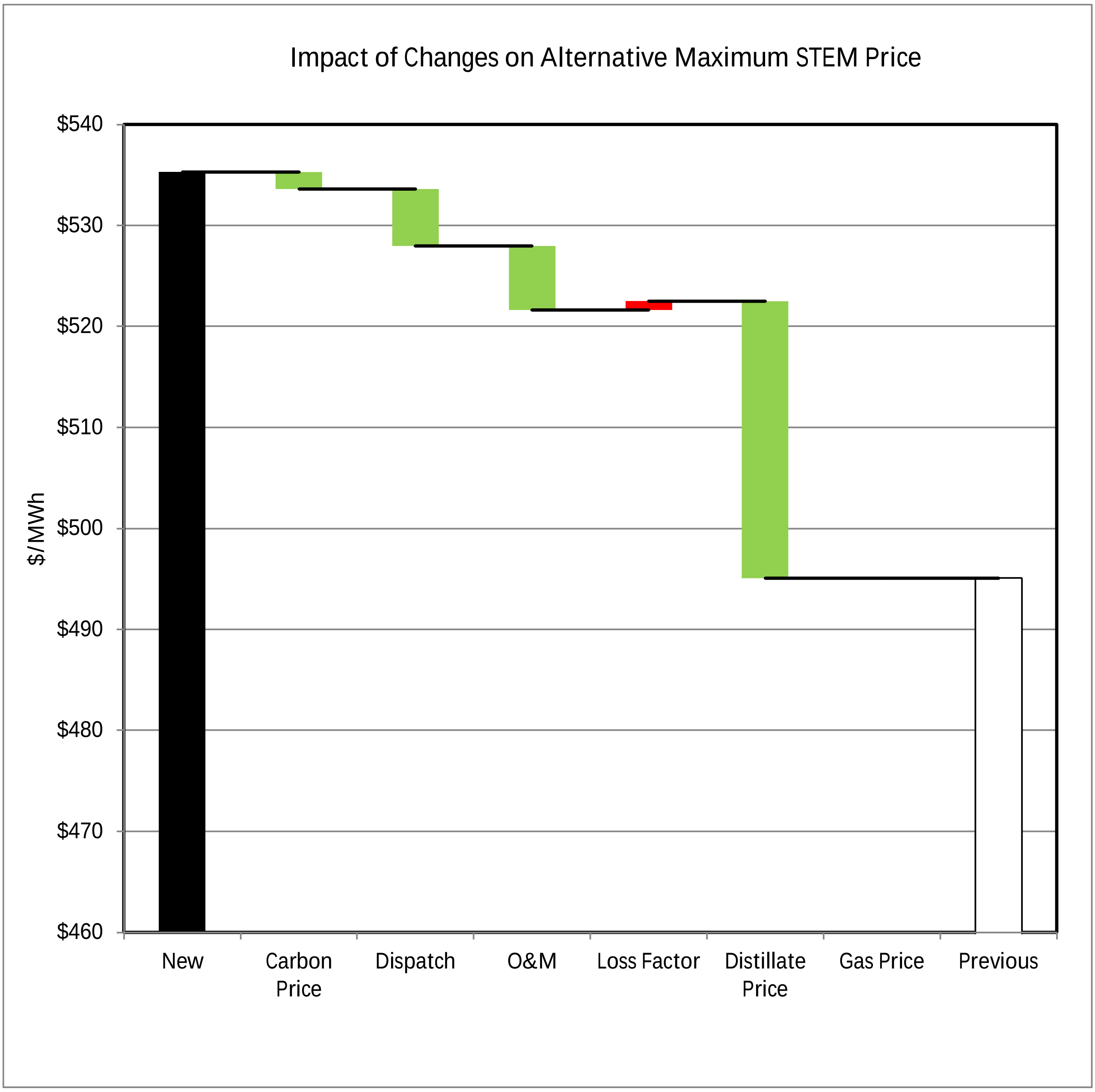
Table 4-6 Analysis of changes to form the waterfall diagram for the Alternative Maximum STEM Price

Step	Label in chart	Changes	Parameters affected (Appendix B)
1	New	The basis for the 2014 Energy Price Limits	
2	Carbon Price	Carbon Price restored to the 2013/14 value of $24.15/tCO2e	CP
3	New Historical Dispatch Patterns	Capacity, run-times and dispatch cycle capacity factor based on the data from 1 January 2009 to 31 January 2013 replaces the data from 1 January 2013 to 31 December 2013.	CAP, CF, RH, and hence MPR
4	O&M Parameters	The O&M costs for the industrial gas turbines were replaced with the 2013 values (reversing CPI and exchange rate adjustments).	VHC, SUC
5	Loss Factor	Restore loss factor to 2012/13	LF
6	Distillate Price	Distillate price was changed from $23.56/GJ to $21.65/GJ, the road freight was moved back to the variable fuel component of the calculation, and the 2012/13 standard deviation was restored	VFC (distillate)
7	Gas Price (No effect)	The spot gas commodity cost distribution was replaced with the distribution that applied in the 2013 review.	VFC (gas)
8	Old	The calculation of the Maximum STEM Price based on the 2013 parameters.	

Table 4-7 Impact of factors on the change in the Alternative Maximum STEM Price

Factor	Impact $/MWh
Carbon Price	$1.70
Dispatch	$5.62
O&M	$6.33
Loss Factor	-$0.86
Distillate Price	$27.43
Gas Price	$0.00

Figure 4-3 Impact of factors on the change in the Alternative Maximum STEM Price



4.5 Cross checking of results

4.5.1 Cross checking dispatch cycle costs with heat rate based on market dispatch

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

Table 4-8 shows a tabulation of the mean values of the dispatch cycle cost using the average heat rate at minimum capacity as well as the dispatch cycle heat rate method. The results are quite similar, with potential for slight over-estimation of the Alternative Maximum STEM Price by using the heat rate at minimum value. For the Maximum STEM Price, the values are $3/MWh lower after rounding using the dispatch cycle method.

Table 4-8 Energy Price Limits using average heat rate at minimum capacity or market dispatch cycle method

	Maximum STEM Price		Alternative Maximum STEM Price	
	Average heat rate at minimum capacity	Dispatch cycle method	Average heat rate at minimum capacity	Dispatch cycle method
Mean value	$295.14	$289.59	$505.65	$496.02
80% POE	$332.00	$329.00	$535.00	$529.00
Margin over expected value (Dispatch Cycle Method)	14.6%	13.6%	7.9%	6.6%

The difference between the proposed Energy Price Limits and the dispatch cycle costs based on dispatch cycle heat rate modelling for Pinjar is about 6.6% of the expected costs for distillate firing and about 13.6% for gas firing[31.] That the values are similar for the Maximum STEM Price reflects a higher number of short dispatch cycles in the historical data. Thus the dispatch cycle cost method is calculating an effective heat rate commensurate with the average heat rate at minimum capacity at the 80% probability of coverage.

[31] Table 4-8 compares the proposed price caps with the expected average dispatch cycle cost and shows the margins as a ratio of the expected average dispatch cycle cost, rather than the cost calculated by clause 6.20.7(b). The use of the average heat rate at minimum produces a slightly higher Maximum STEM Price due to the assumption about operation at minimum stable capacity which is not fully reflected in historical dispatch. The difference is immaterial.

5. Public consultation

A Draft Report version 1.10 was published for public consultation. One written submission was received from Community Electricity. The response was supportive of the change to the Energy Price Limits as quoted from the submission:

“Community supports the draft report and in particular the proposed values for the Maximum STEM Price and Alternative Maximum STEM Price.

The Energy Price Limits are a central feature of the Wholesale Electricity Market and we support the relatively low levels and continuity with previous years.”

6. Conclusions

The analysis of the costs of short term running in the SWIS has confirmed the need to increase values on 1 July 2014 from those that apply currently. From 1 July 2014 it is proposed that:

- The Maximum STEM Price should be $322/MWh, and
- The Alternative Maximum STEM Price should be $92.78/MWh + 19.494 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ.

At $22.70/GJ Net Ex Terminal Price the proposed Alternative Maximum STEM Price is $535/MWh.

The most significant influences on the Alternative Maximum STEM Price have been the increase in fuel price and variable O&M costs, driven by the reduction in the AUD:US exchange rate. Removing variations in the assumed Ex Terminal price, the proposed Alternative Maximum STEM Price is still higher than the proposed price in the 2013 review due to an increase in O&M costs driven by changes in exchange rates and the reduction in the assumed average run time and minimum capacity for Pinjar.

The increase in the Maximum STEM Price since last year's assessment has also been primarily due to the impact of the reduction in the AUD:US exchange rate on O&M costs per MWh and the reduction in the assumed average run time and minimum capacity for Pinjar.

Table 6-1 summarises the prices that have applied since October 2011 and the subsequent results obtained by using the various methods. New values are rounded to the nearest dollar as more precise values are not warranted by the accuracy of the analysis.

Table 6-1 Summary of price caps

No.	History of proposed and published prices	Maximum STEM Price ($/MWh)	Alternative Maximum STEM Price ($/MWh)	Comment
1	Published Prices from 1 October 2011	$314	$524	From IMO website
2	Published Prices from 1 June 2012	$314	$571	From IMO website
3	Published Prices from 1 July 2013	$305	$523	From IMO website
4	Published Prices from 1 May 2014	$305	$566	From IMO website[32]
5	Proposed Prices to apply from 1 July 2014	$332	$535	Based on $22.70/GJ for distillate, Net Ex Terminal.
6	Probability level as Risk Margin basis	80%	80%	

Notes:

(1) The fifth row shows the risk adjusted costs that would apply if the cost analysis is conducted solely using the average heat rate at minimum capacity. Start-up fuel consumption was included. As required in clause 6.20.7(b) these are the proposed price caps to apply from 1 July 2014 based on a projected Net Ex Terminal distillate price of $1.258/litre excluding GST.

(2) In the sixth row, the probability levels that are proposed to be applied to determine the Risk Margin for setting the price caps.

[32] http://www.imowa.com.au/market-data-pricelimits accessed 5 May 2014

Appendix A. Market Rules related to maximum price review

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

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

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

a) may propose revised values for the following:

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

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

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

Where:

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

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

iii. Heat Rate is the mean heat rate at minimum capacity based on 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 the generator relative to the Reference Node.

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

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

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

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

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

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

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

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

Appendix B. Formulation of the Maximum Stem Price

B.1 Formulation of the Energy Price Limits

The following represents the formulae used to model the formula in clause 6.20.7(b) of the Market Rules, excluding the Risk Margin factor, broken down into the full set of sub components. It is the formulae below that are used to calculate the 1000 plus samples used to create the probability curve for the Energy Price Limits. The primary formula below includes the start-up fuel cost, the start operating cost and the fuel cost components, and emissions.

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

Where:

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

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

RH is the running hours per dispatch cycle based on a sampled distribution derived from market observations of dispatch. This distribution is confidential and is not included in this report, apart from the average of 116.8 hours for Parkeston shown in Table D- 5;

MPR is the MWh generated per run based on a sampled distribution derived from market observations and derived as a function of run-time. This distribution is confidential and is not included in this report, apart from the average value of 3345.8 MWh for Parkeston shown in Table D- 5;

MPR = CAP * RH * CF

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

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

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

VFC is the variable fuel cost in $/GJ in the range $2/GJ to $24/GJ or lower if the break-even price with distillate is lower;

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

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

FER is the fuel emission rate in tCO_2e per GJ for the delivered fuel including the components expected to be passed through in gas supply and transport.

CP is the carbon price in $/$tCO_2e$

SUC is the cost per start ($/start) when maintenance costs depend on the number of starts per year using the time discount formulation:

CPS(i) = X(i)/Log(1+DR)*(1-(1+DR)^(- CL/SPY))*SPY/CL

SUC = Sum [CPS(i)]

Where:

CPS(i) is the cost per start for each maintenance stage (i)

Sum [CPS(i)] is the summation of the values of CPS(i) for all of the maintenance stages (i) in the full cycle.

X(i) is the maintenance expenditure for each maintenance stage

DR is the discount rate taken to be 9% per annum (pre-tax real);

CL is the maintenance cycle length at 2400 starts;

SPY is the sampled number of starts per year;

Log is the natural logarithm.

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

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

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

LF is the loss factor.

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

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

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

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

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

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

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

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

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

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

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

For the purpose of the equation defined in clause 6.20.7(b), the Fuel Price is adjusted to include the emission cost as follows:

Adjusted Fuel Cost = (VFTC+ (FT + VFC * FSR)/VFTCF + FER * CP)

The treatment of these variables as stochastic variables is summarised in Table B.1. The means, minima and maxima and standard deviations for the heat rate (AHRN) were as derived from the dispatch cycle parameters based on the minimum capacity level. Over the 1000 samples, the normal variables were typically between ±3 standard deviations unless clipped to a small range around the mean. The sampled number of starts per year was given a minimum value of 10. The Start-up cost SUC, MPR, run times RH and plant sent-out capacity CAP and dispatch cycle capacity factor CF were derived from confidential market data. The start-up cost SUC depends on the distribution of the number of starts per year for the industrial gas turbines. The loss factor LF was as published by Western Power Networks for 2013/14. The start-up fuel consumption was based on the estimates developed by Jacobs SKM.

Table B.1 Structure of the stochastic model of cost

Variable	Mean/Mode	Sampled Minimum	Sampled Maximum	Standard Deviation	Distribution Type	Comment
VHC	205.00	$140	$273	10%	Normal	Aero derivative - Goldfields
AHRN	12.396 GJ/MWh	11.127	14.146	0.459 *	Normal	Aero derivative – Goldfields (including variation due to minimum capacity uncertainty)
AHRN	19.153 GJ/MWh	16.40	23.70	1.071 *	Normal	Industrial – Pinjar (parameters obtained from the sampled distribution including variation due to minimum capacity uncertainty)
VFTC	$2.229	$1.549	$3.114	$0.273 *	Truncated lognormal	Aero-derivative - Goldfields
VFTC	$1.795	$1.114	$2.680	$0.273 *	Truncated lognormal	Industrial
FT	$5.70	$5.70	$5.70		None	Aero-derivative
FT	0.00	0.00	0.00	0.50%	Fixed	Industrial
VFC	$9.31	$5.00	$21.40	$2.00 *	Discrete	Gas supply after break-even price capping
FSR	100%	100%	100%		Fixed	
VFTCF	89.9%	66%	100%	6.70% *	Truncated lognormal	VFTCF = 1 for distillate
FER	0.05533 tCO_2e/GJ gas				None	Gas to Pinjar
FER	0.05493 tCO_2e/GJ gas				None	Gas to Parkeston
FER	0.0695 tCO_2e/GJ distillate				None	Distillate
CP	$25.40/$tCO_2e$				None	
SUFC	3.53 GJ	2.400	4.590	10%	Normal	Aero-derivative
SUFC	3.50 GJ	2.376	4.543	10%	Normal	Industrial
SUFC	3.54 GJ	2.407	4.602	10%	Normal	Aero-derivative (liquid fuel)
SUFC	3.51 GJ	2.382	4.555	10%	Normal	Industrial (liquid fuel)

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

Appendix C. Gas prices in Western Australia in 2014-15

C.1 Introduction

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

This section presents Jacobs SKM's assessment of the appropriate spot gas price range to apply in the derivation of the Maximum STEM Price. The assessment is based on publicly available information regarding gas prices in WA. As Jacobs SKM did not undertake the corresponding analysis for the 2013/14 price review, Jacobs SKM has estimated both 2013-14 and 2014-15 gas price distributions using its own approach, for comparison with the values used in 2013/14.

C.2 Gas commodity prices

C.2.1 The WA gas market

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

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

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

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

  gasTrading's website provides information regarding volumes and prices of trades. Typical volumes traded range from 5TJ/d to 15TJ/d (0.5% to 1.5% of WA domestic gas volumes) and prices paid range from $2.00/GJ to $10.50/GJ. The "market" does not settle at a single daily price but a range of prices reflecting a series of bilateral transactions.
- The gas trading platform operated by Energy Access Services since 2010. Energy Access has nine members but usage of the platform is unknown.

The reasons parties may choose to participate in each of the above alternatives may include preferences to deal directly with counterparties, their scale of trading, preferred periods of trades (daily, monthly) etc.

C.2.1 Estimating Future Gas Spot Market Prices

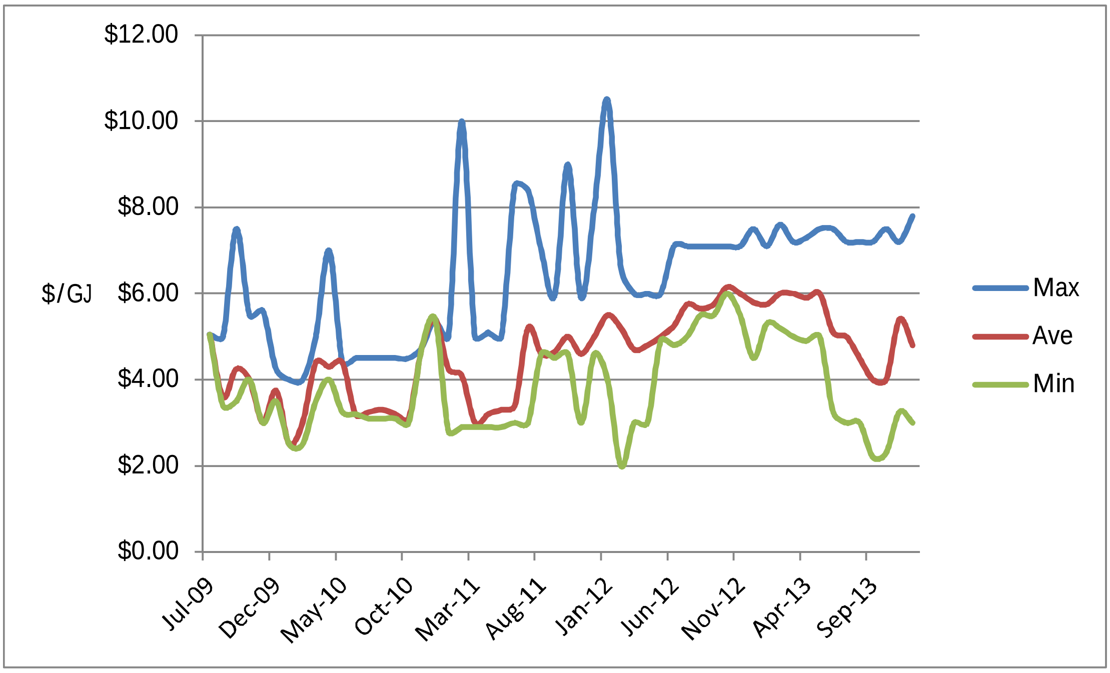
Jacobs SKM believes that the most appropriate approach to projecting future spot prices for use in setting the Maximum STEM Price is to consider the impact of future gas production costs, contract prices and trading conditions on spot prices. Ideally, spot prices would include estimates of all spot prices discussed above, including those which are not published. For the non-published prices this would involve a rigorous survey of market participants, to avoid using potentially unreliable anecdotal information. Unfortunately this was considered to be unachievable within the review time frame. Consequently we have used gasTrading's spot prices as representative of the spot market as a whole.

In considering the period to the end of 2014/15, Jacobs SKM believes that there will be significant changes in gas contract pricing owing to the termination of some legacy contracts and the commencement of higher priced replacement contracts. There may be corresponding changes in production costs where the new contracts are supplied from newly constructed production facilities, however it is not considered likely that production costs at older facilities will have increased materially. Furthermore, contract prices are known to, and affect the behaviour of, both gas producers and gas shippers who participate in spot markets, whereas production costs are known only to producers. Consequently our approach has focussed on the impact of contract prices and trading conditions on spot prices.

C.2.2 gasTrading Spot Market Prices

The gasTrading Spot Market matches individual bids and offers over a range of prices, that is, it is not a single price market. gasTrading reports daily minimum, average and maximum prices on a monthly basis (Figure C-1). Up to the end of 2013, the price range was $2.00/GJ to $10.50/GJ and the (unweighted) average was $4.57/GJ.

Figure C- 1 gasTrading spot market daily price history



gasTrading also provides summary information on offers to purchase and gas scheduled (Table C- 1). This tells us that insufficient gas was bid at low enough prices to match demand at low prices. More precisely: demand at prices below $3.60/GJ was not met because there were no supply bids below $3.60/GJ; some demand at prices between $3.60/GJ and $7.20/GJ may not have been met; there may have been supply at prices above $7.20/GJ for which there was no demand. The gasTrading website separately confirmed the availability of supply at more than $7.20/GJ.

We note the following in relation to the Maximum STEM Price:

- Jacobs SKM considers that only the maximum prices are relevant, because they represent the maximum price that a buyer was prepared to offer for gas at the time, though it is not known whether any of the buyers was a generator.

- The level of average spot prices generally reflects average contract prices (refer to section C.2.3 below). This suggests that buyers are under little pressure to purchase spot gas and that the market is currently well supplied. As some new contracts are priced well above this level it is not relevant to the Maximum STEM price.
- The maximum prices may not represent the highest price faced by a generator because the quantities bid are low. A 40 MW open cycle generator running for 6 hours requires approximately 3 TJ, a significant proportion of daily trades. To attract sufficient supply bids, the generator may have to offer more than the maximum price reported above.

Table C- 1 Offers to purchase and gas scheduled for the period February 2014

	Offers to Purchase	Scheduled for Sale
Total quantity	531.40 TJ	281.96 TJ
Maximum price	$7.20/GJ	$7.20/GJ
Average Price	$3.85/GJ	$4.33/GJ
Minimum Price	$2.95/GJ	$3.60/GJ

The distribution of the gasTrading spot market maximum prices since 2009 has been bi-modal (Figure C- 2), with distribution parameters as set out in Table C- 2. Since June 2012 maximum prices have been in a narrow band between $7.10/GJ and $7.80/GJ and averaging $7.30. It is noted that this was shortly after the opening of the new Devil Creek gas plant, whose major customer, the Sino Iron Project, was not ready to use its full contract quantities and is believed to have onsold gas to other users. These factors are considered likely to be related and as the Sino Iron Project increases production the excess capacity is likely to be absorbed. While difficult to predict the rate at which this will occur[33], for the purpose of this analysis Jacobs SKM has assumed that there will be a 50% reduction in excess capacity from the Sino Iron Project by 2015.

The relationship between gasTrading spot market prices and the prices at which other shorter term trades are transacted is not known but Jacobs SKM considers it reasonable to assume that price levels would be similar, perhaps with a broader distribution.

[33] Sino Iron is scheduled to complete all six production lines in 2016 (The West Australian, 21 February 2014).

Figure C- 2 Distribution of gasTrading spot market maximum prices since 2009

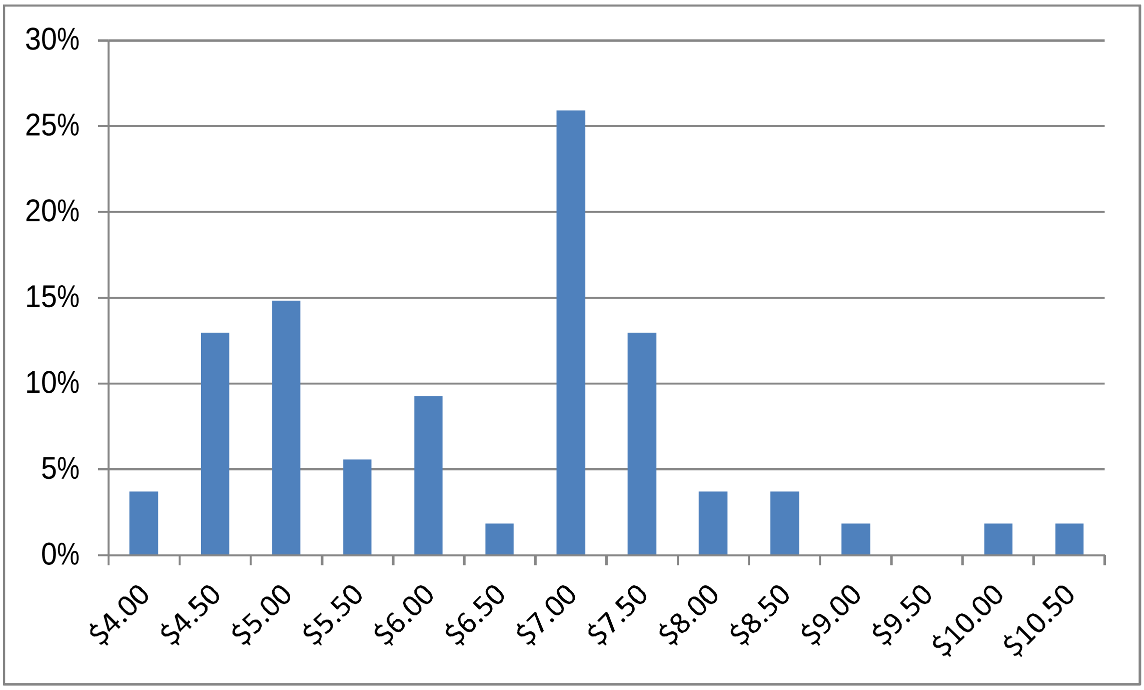


Table C- 2 gas Trading spot market price distribution parameters

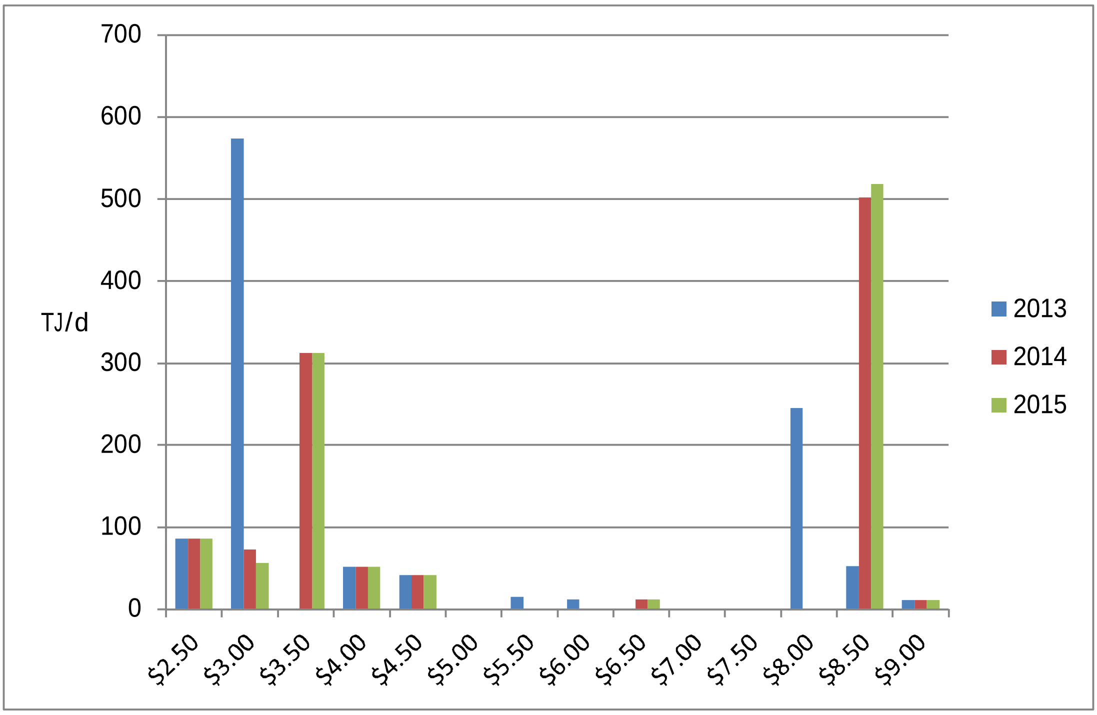
Parameter	Value 2009-2013	Value June 2012-2013
Average	$6.41/GJ	$7.28/GJ
Median (50 percentile)	$7.00/GJ	$7.20/GJ
Lower mode	$5.00/GJ	$7.00/GJ
Upper mode	$7.00/GJ	$7.00/GJ[34]
80% lower bound (90 percentile)	$4.50/GJ	$7.10/GJ
80% upper bound (10 percentile)	$7.94/GJ	$7.52/GJ

C.2.3 WA Contract Prices

Jacobs SKM's estimates of gas contract volumes available at various price levels are presented in Figure C- 3. Both prices and volumes are based on public sources, principally government funded reports, company media releases and news items. For some contracts only the volumes are known and prices have been estimated from similar contracts entered at a similar time.

[34] The upper and lower mode were the same in this financial year as there was not a lot of variable in spot market prices trading around this $7/GJ level

Figure C- 3 Jacobs SKM estimates of gas contract volumes (calendar year)



All of the contract data should be regarded as estimates. Nevertheless two features are clear:

- The distribution of contract prices is bi-modal, reflecting lower prices still applicable to some legacy contracts entered before 2006
- The weight of the distribution at high prices increases in 2014 owing to the termination of some legacy contracts and their replacement with new higher priced contracts, such as those sourced from the Macedon gas field.

Two tests of the overall accuracy of the contract data are available, as reported in Table C- 3. Differences are relatively modest.

Table C- 3 Average WA gas contract values

	Actual	Jacobs SKM estimate
WA average value of gas at plant gate 2012/13	$4.33/GJ[35]	$4.49/GJ
North West Shelf JV average revenue 2013	$4.29/GJ[36]	$4.10/GJ

C.2.4 Linking spot and contract prices

Our approach to deriving prices applicable for assessment of the Maximum STEM Price is based on estimating the impact of the contract price movements illustrated in Figure C- 3 on the gasTrading maximum spot price distribution and then allowing for a broader price distribution to cover other short term transactions, as discussed below. The first step is to construct a simple model that transforms the 2013 contract price distribution into the gasTrading maximum spot price distribution. This model assumes the following linkage between contract and gasTrading spot prices:

- Most of the gas in each contract is scheduled to meet the buyers demand.

[35] Published by WA Department of Mines and Petroleum in Petroleum1213.
[36] Derived from production and revenue figures reported in Woodside 4th Quarter 2013 Report.

- A proportion of what is not scheduled is assumed to be bid into the gasTrading spot market, with equal proportions from each contract except the Sino Iron Project contract and existing users who are assumed to be purchasing from them. In particular it is assumed that Synergy is one such purchaser, using the Sino Iron gas to maintain available volumes in its lower cost contracts for the future. These Synergy contracts are assumed not to be bid into the spot market.
- For low priced contracts the prices bid are the contract prices plus a margin of $0.50/GJ while higher priced contracts are assumed to be bid at cost.
- Offers to purchase are 2-3% of total market demand, which varies between 900TJ/d and 1075 TJ/d. The distribution of total demand is based on GBB data.
- The maximum spot price is determined by a simple “bid-stack” approach.
- Model parameters have been adjusted to obtain a good fit against the gasTrading spot market prices

The model predictions of maximum spot prices using calendar 2013 contract data are compared with the actual gasTrading maximum spot price distribution in Figure C- 4. The model captures the bi-modal nature of maximum spot prices together with the modal values and the cumulative distributions (Figure C- 5) are very well matched, particularly at their upper ends.

Figure C- 4 Probability distributions of gasTrading actual and modelled maximum spot prices

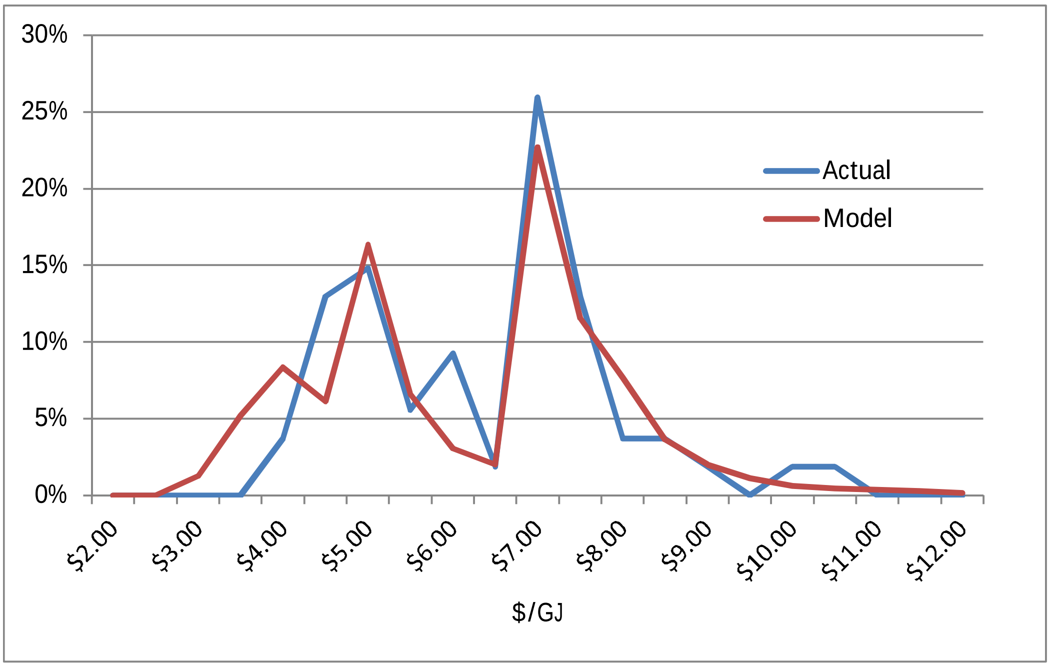
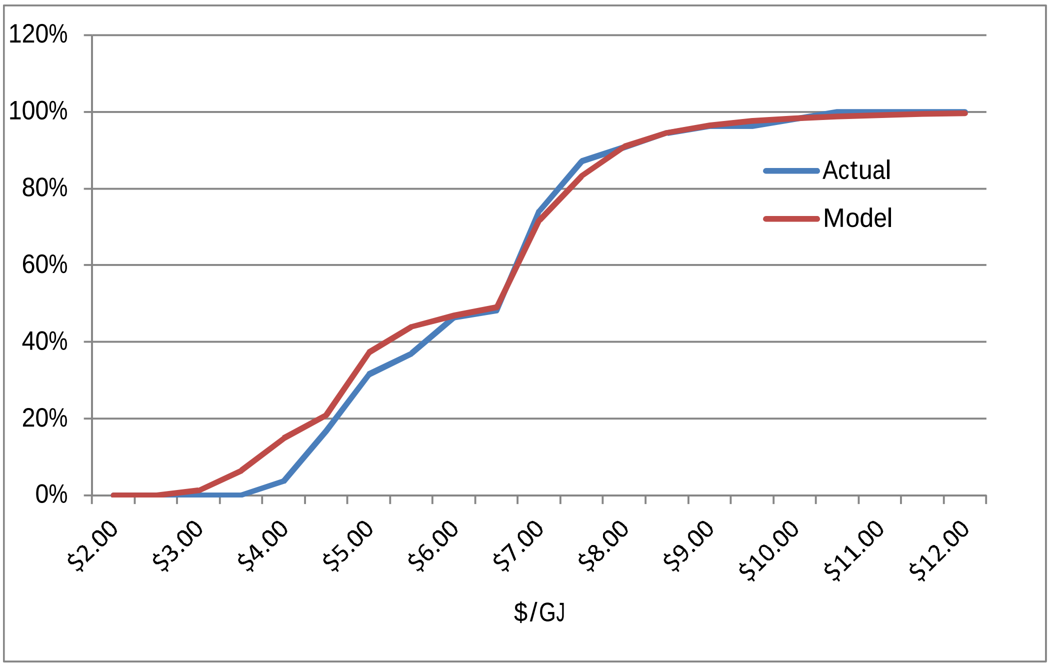


Figure C- 5 Cumulative probability distributions of gasTrading actual and modelled maximum spot prices



C.2.5 Spot price projections

Using this model, including assumptions regarding its relationship to other short term prices outside the gasTrading platform, we have estimated the impacts of contract price changes in calendar 2014 and 2015 and then estimated the financial year spot prices for 2013/14 and 2014/15 (Figure C- 6). Trading conditions for Sino Iron and Synergy are projected to remain the same in 2014 as in 2013, but in 2015 the trading of Sino Iron gas is assumed to reduce by approximately 50%. As would be expected, the model suggests that the increasing weight of higher priced contracts leads to an increasing weight of high spot prices[37]. Cumulative distributions are shown in Figure C- 7, including the simulated 2013/14 distribution provided by ACIL Tasman for the 2013 review. The distribution parameters are also compared with those used in the 2013 review in Table C- 4.

Table C- 4 Spot price distribution parameters

Parameter	ACIL Tasman 2013/14	Jacobs SKM 2013/14	Jacobs SKM 2014/15	Change 2013/14 to 2014/15
Average	$7.99/GJ	$8.19/GJ	$9.31/GJ	$1.12/GJ
Median (50 percentile)	N/A	$7.96/GJ	$8.52/GJ	$0.56/GJ
Mode	$6.80/GJ	$8.50/GJ	$8.50/GJ	$0.00/GJ
80% lower bound (90 percentile)	$5.02/GJ	$4.74/GJ	$7.52/GJ	$2.78/GJ
80% upper bound (10 percentile)	$11.56/GJ	$10.47/GJ	$11.12/GJ	$0.65/GJ

[37] For example, the mode of maximum spot gas prices in 2013/14 is higher than the mode predicted by the model for calendar year 2013 due to this change in weighting towards higher contract prices.

Figure C- 6 Modelled probability distributions of maximum spot prices for 2013/14 and 2014/15[38]

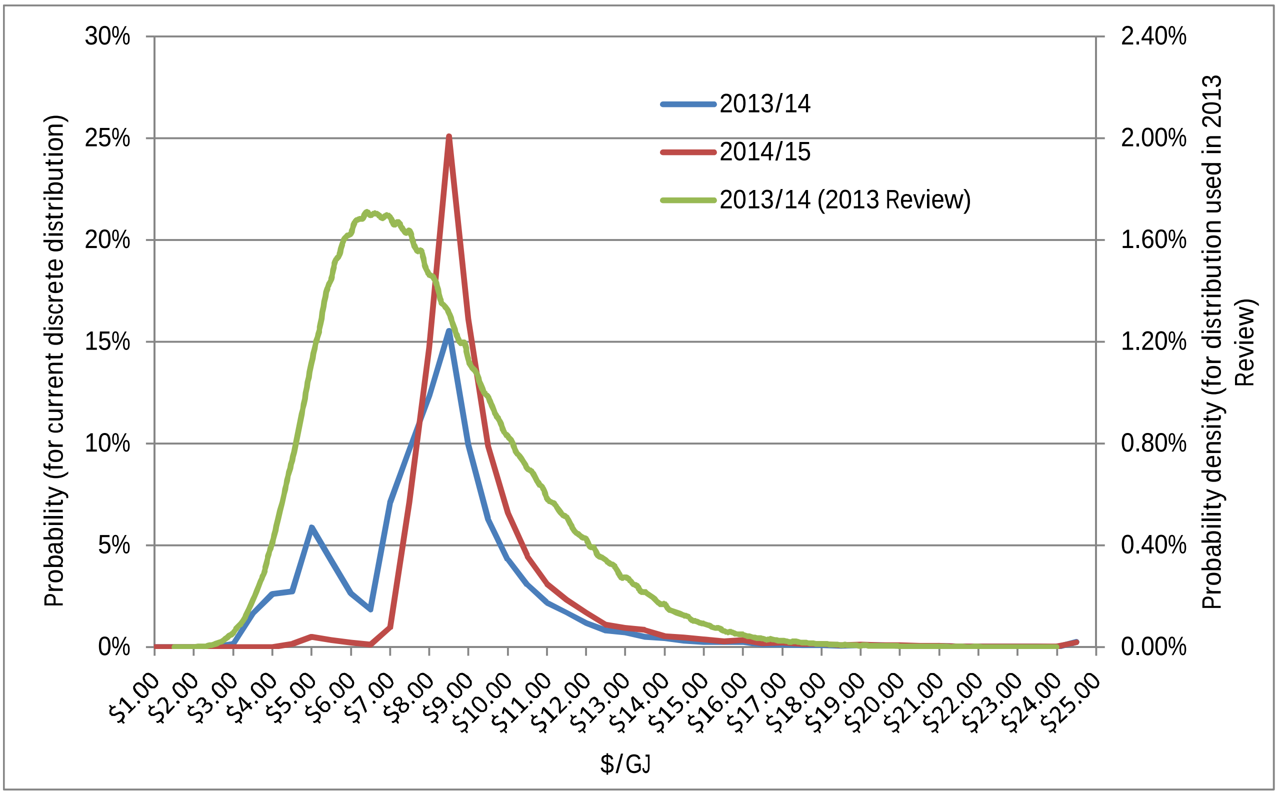
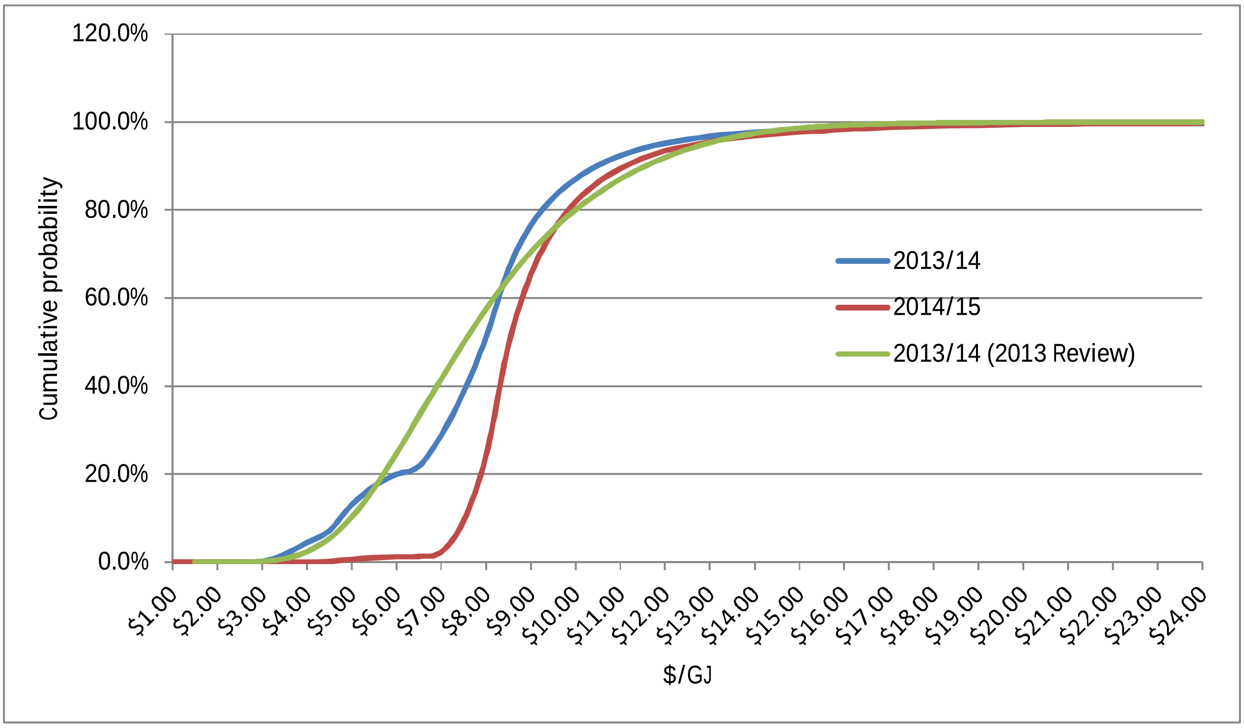


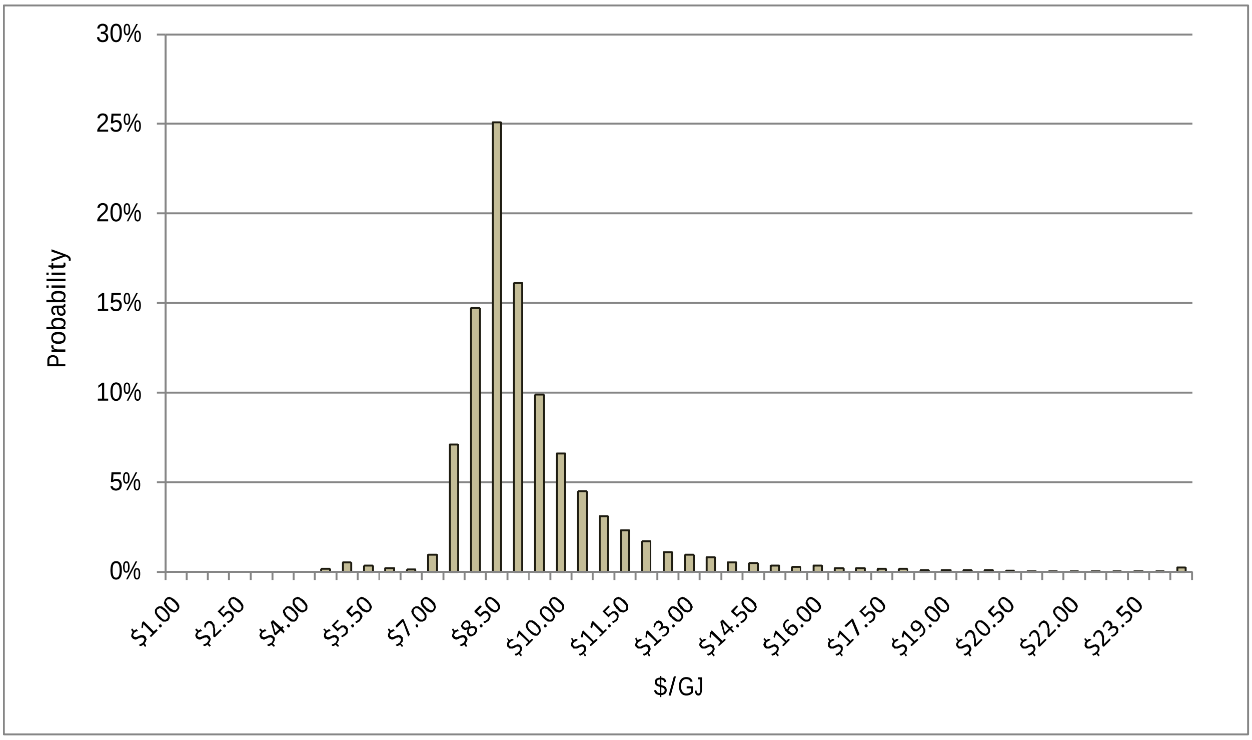
Figure C- 7 Modelled cumulative distributions of maximum spot prices for 2013/14 and 2014/15



[38] A secondary y-axis has been needed for the 2013/14 distribution used in the 2013 review as the current distributions are discrete whereas the previous distribution was continuous. With a continuous distribution, the probability of obtaining any given value is much smaller.

In previous years, three lognormal distributions have been used to represent the spot gas price uncertainty. However, the derived distribution for 2014/15 does not fit any theoretical distribution very well. Therefore, we have sampled directly from the 2014/15 discrete distribution in Figure C- 6, re-displayed in Figure C- 8 for clarity.

Figure C- 8 Discrete spot gas probability distribution for modelling spot gas uncertainty, 2014/15



As discussed in Section 2.3.3, this spot gas price is further capped by the break-even price at which a generator would be indifferent between using gas and distillate. This maximum gas price is calculated for each of the 1000 simulated dispatch cycles.

C.3 Gas Transmission Costs

C.3.1 Transmission tariffs

Transmission costs on the two pipelines considered in this Energy Price Limit review are set by a combination of regulation by the Economic Regulation Authority under the National Gas Regulations (NGR) and negotiation between the pipeline operators and gas shippers.

C.3.1.1 Dampier Bunbury Natural Gas Pipeline

Although the DBNGP is a Covered (regulated) pipeline, the tariffs until 2016 were set by negotiation between the pipeline and shippers, to cover recent capacity increases. The standard full haul (T1) tariff applicable to delivery into the Perth region as at 1/1/2014 at 100% load factor was $1.552121/GJ[39]. The tariff is comprised of two components, a reservation component charged on capacity reserved and set at 80% of the aggregate, and a commodity component charged on volumes shipped, set at 20% of the aggregate.

The tariff escalates from year to year at CPI-2.5%[40], with the result that it is virtually static in nominal terms, and we assume that it will have a value of $1.55/GJ over the 2014/15 financial year.

[39] DBNGP Access Guide, 10 February 2014.
[40] DBP Precedent Shipper Contract June 2013

C.3.1.2 Goldfields Gas Pipeline

Capacity on the GGP is partly covered and partly uncovered. Covered capacity amounts to 109 T/d with the current delivery configuration, of which 3.8 TJ/d was uncontracted as at 1 January 2010. Uncovered capacity, which relates to recent expansions, is estimated to be approximately 41 TJ/d. The regulated tariffs for the Covered capacity and the tariff range quoted for the Uncovered capacity are shown in Table C- 5, together with the total charge in Kalgoorlie (distance 1380km). The toll and capacity reservation charges are both applied to capacity.

Table C- 5 GGP tariffs for the first quarter of 2014

	Toll Charge $/GJ	Capacity Reservation Charge $/GJ/km	Throughput charge $/GJ/km	Cost at 100% load factor in Kalgoorlie $/GJ
Covered capacity[41]	$0.214195	$0.001470	$0.000385	$2.77
Uncovered, lower[42]	$0.387399	$0.002681	$0.001009	$5.48
Uncovered, upper	$0.468752	$0.003245	$0.001220	$6.63

[41] Quoted on APA website
[42] Quoted on GGP website

C.3.2 Spot transportation

C.3.2.1 Dampier Bunbury Natural Gas Pipeline

The DBNGP offers capacity on a spot basis[43] to shippers, via a bidding process in which:

- DBP sets capacity available and the minimum price
- Shippers bid prices and volumes
- Capacity is allocated to the highest bid, then the next highest until the capacity is sold or all bids are satisfied.

No data is available on price outcomes but we understand that the minimum price is typically set 15% above the T1 tariff rate. In the current climate of capacity being in excess of transport requirements we would expect limited demand for spot capacity and correspondingly low prices.

C.3.2.2 Goldfields Gas Pipeline

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

C.3.3 Transmission costs

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

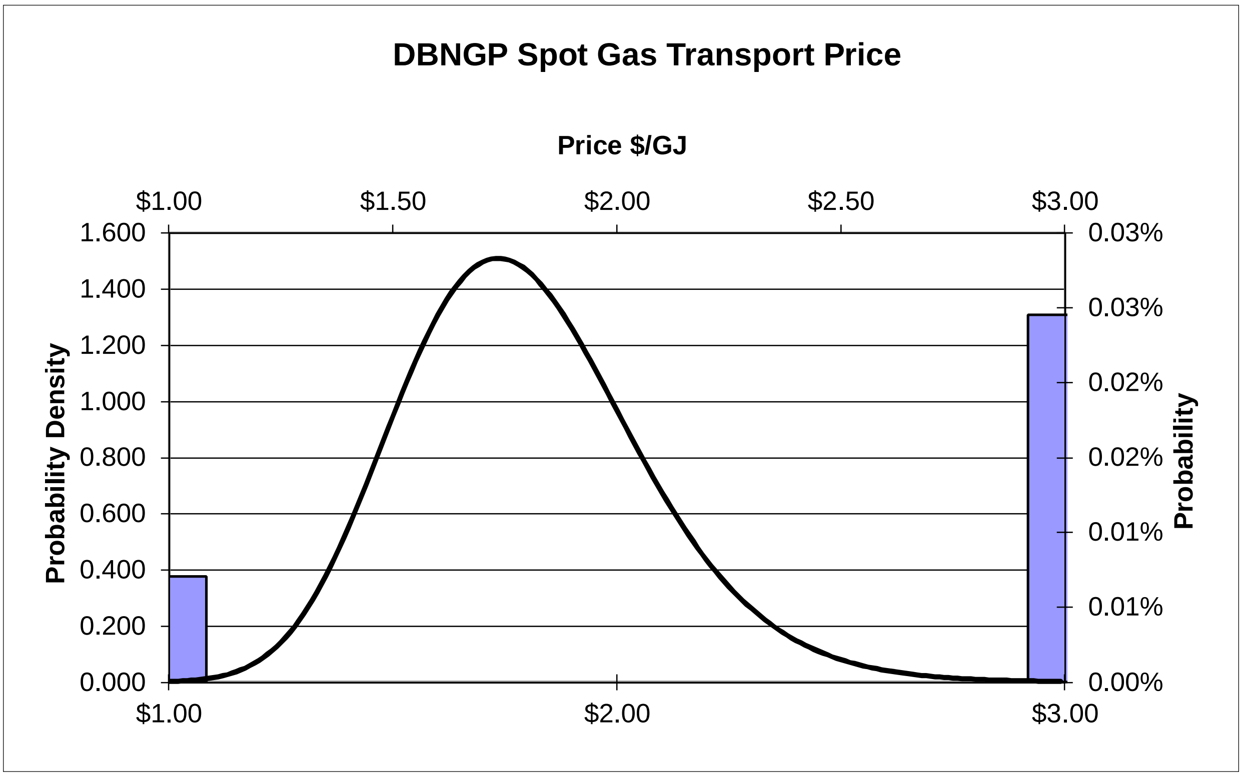
- For DBNGP, the estimated minimum spot price converted into a range by adding a lognormal distribution with a standard deviation of $0.15/GJ.
- For GGP a 10% premium on the uncovered lower estimate at 100% load factor, that is, $6.14/GJ for 2014/15.

For the gas transport to Perth on DBNGP, the lognormal distribution assumed has an 80% confidence range being between $1.46/GJ and $2.15/GJ with a most likely value (mode) of $1.735/GJ. The mean value of the transmission charge is $1.795/GJ. The distribution shown in Figure C- 9 represents this uncertainty in the gas transport cost. The gas cost range was taken between $1/GJ and $3/GJ which is consistent with the assumptions adopted in the 2013 review.

Gas delivered via the GGP is sourced from production plants that inject gas into the DBNGP and directly into the GGP. Gas injected into the DBNGP is backhauled or part-hauled to the inlet of the GGP. As no backhaul or part-haul spot capacity is offered by DBNGP, the DBNGP spot price is added to the cost of delivering gas to Kalgoorlie. This simplistic assumption may lead to an overestimation of the gas transport cost to Parkeston since it is not known what proportion of gas to the power station is injected directly into the GGP and/or into the DBNGP. Given that the Parkeston aero derivative units do not currently set the Maximum STEM Price, this conservative assumption is considered reasonable for this analysis, but may need to be reconsidered should the Parkeston units become genuine candidates for setting the Maximum STEM Price in the future.

[43] Details were provided in DBP's evidence to the WA Parliamentary Inquiry into Domestic Gas Prices in 2010.

Figure C- 9 Capped lognormal distribution for Dampier to Bunbury Pipeline spot gas transport cost



C.3.4 Mondarra Storage

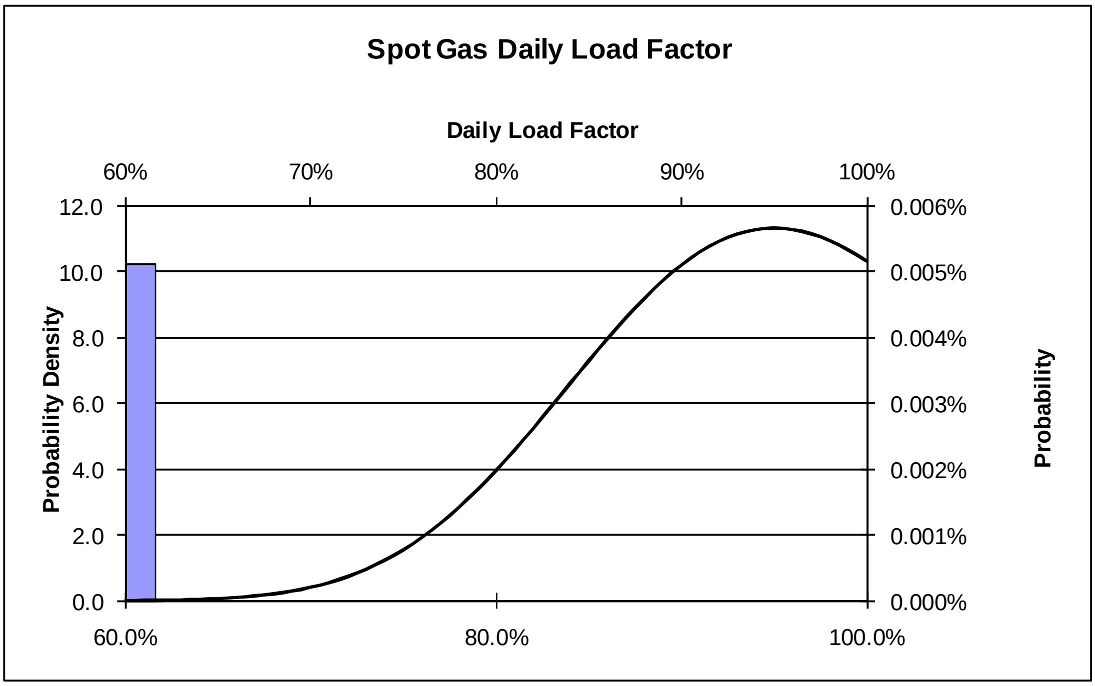
The Mondarra Storage operated by the Australian Pipeline Trust (APA) commenced operations during 2013. Until now it appears to have been primarily in the “fill” mode and its longer-term patterns of use are not yet clear. Gas storages in other markets serve two functions: emergency supply when production or pipeline capacity is accidentally lost; and additional peak or seasonal supply, subject to availability of pipeline capacity from the storage to end-users. The latter function also involves price arbitrage, because gas is stored during lower price periods and re-used during higher price periods, assuming low/high prices correlate with low/high demand or high/low supply. At a time of generally rising prices lower cost gas can also be stored for future use in a longer timeframe.

The impact of Mondarra should be to reduce the cost of gas supply, including gas spot prices. However whether or when it will do this is not clear. Its impact should be more material when Synergy starts to take delivery of gas from the Gorgon development in 2016 or later and we therefore recommend not to include any impact in the 2014 Energy Price Limit review.

C.4 Daily gas load factor

The probability distribution used to represent the uncertainty of the daily gas supply load factor is shown in Figure C- 10. The mode of the continuous distribution is at 95% with an 80% confidence arrange between 80% and 98%. There is a 0.005% probability of a value at 60%. The mean of the composite daily load factor distribution is 89.91%. This is consistent with the model provided by ACIL Tasman for the 2013 review.

Figure C- 10 Capped lognormal distribution for modelling spot gas daily load factor uncertainty



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

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

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

- The gas transportation cost is supplemented by the Gas to the Goldfields Pipeline (GGP)
- The carbon cost for gas transport (in $/GJ) is slightly lower mainly due to shorter pipeline distances

  The distillate road freight cost is greater given the larger distance travelled (5.3 Acpl excluding GST and excise compared to 1.3 Acpl for Pinjar)
- The O&M cost is determined by running hours instead of starts
- There is a 43% cost penalty on the variable O&M cost for liquid firing because the aero-derivatives require more frequent maintenance when liquid fired. This arises from the Hot Rotable exchange which is required every 12,500 hours for liquid firing instead of 25,000 for gas firing.
- The transmission loss factor differs for Parkeston (1.2012)
- The assumed heat rate and start-up fuel consumption differs for Parkeston as described in Section D.4 below

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

D.1 Run times

Like Pinjar, the frequency of starts and run times for Parkeston appear to have materially changed in the past 18 months. The evidence is presented in the confidential Appendix for the IMO. Therefore, to be consistent with the treatment of the Pinjar units, only market dispatch information from 1 January 2013 to 31 December 2013 has been used.

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

D.2 Gas transmission to the Goldfields

Having assessed the likely conditions for spot trading of gas transmission capacity, Jacobs SKM have concluded that the appropriate prices for delivery to the Goldfields from 1 July 2014 should be $6.14/GJ plus the DBNGP transport price with an 80% confidence range between $1.46/GJ and $2.15/GJ for transport to the Perth region. There is virtually no uncertainty about the price of spot transport to the Goldfields. This GGP tariff consists of a fixed component of $5.70/GJ which is divided by the daily load factor and $0.43/GJ which is variable and unaffected by the daily gas supply load factor.

The resulting modelled delivered gas price as compared with the equivalent delivered price for the industrial gas turbines at Pinjar is shown in Figure D- 1. The modelled delivered gas price for the Goldfields region had an 80% confidence range of $16.56/GJ to $21.83/GJ with a mode of $18.30/GJ and a mean of $18.90/GJ. The key features of the delivered gas price for Parkeston are provided in Table D- 1.

Figure D- 1 Sampled probability density of delivered gas price for peaking purposes (excluding carbon price)

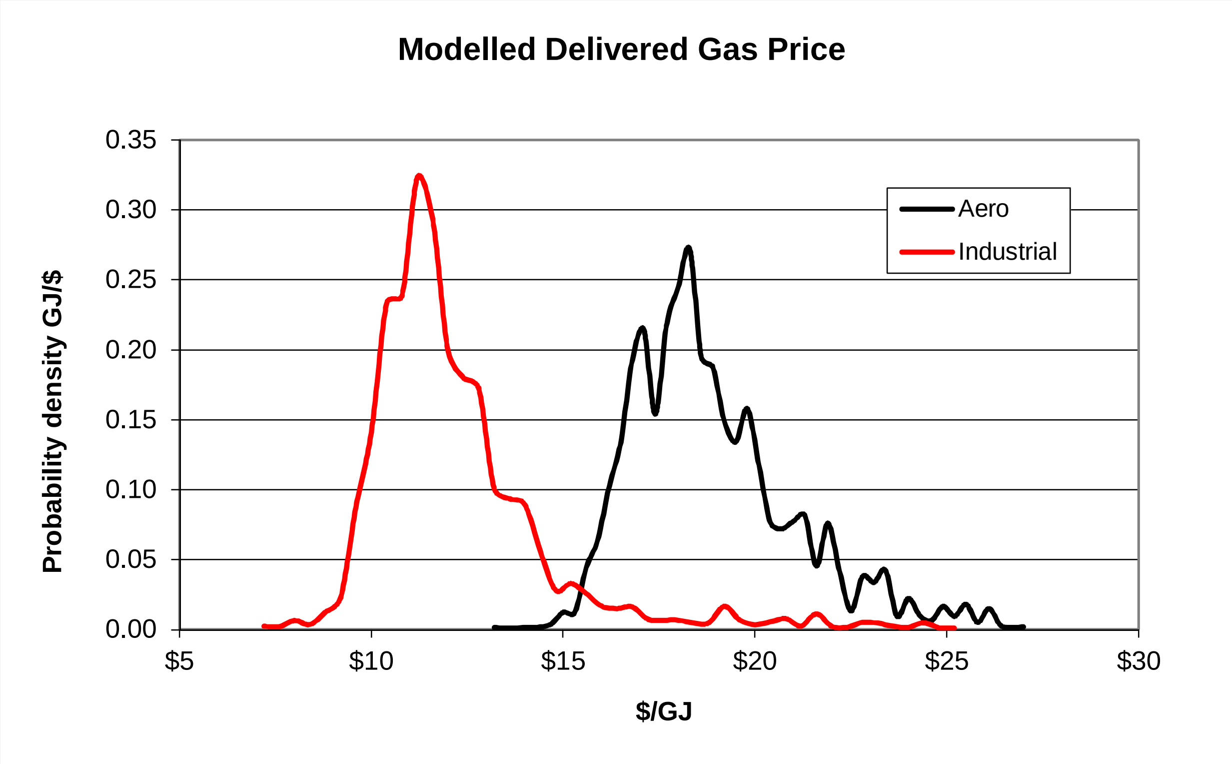


Table D- 1 Delivered gas price for Parkeston gas turbines

Delivered Gas Prices as Modelled	
	Parkeston
Min	$12.81
5%	$16.13
10%	$16.56
50%	$18.44
Mean	$18.90
Mode	$18.30
80%	$20.44
90%	$21.83
95%	$23.31
Max	$27.43

D.3 Distillate for the Goldfields

The Free into Store price of distillate at 144.173 Acpl for Parkeston applies after applying a road freight cost of 5.83 Acpl to Parkeston. This equates to a diesel price of $1.311/litre ex GST for Parkeston. After deducting 38.14c excise and applying a calorific value of 38.6 MJ/litre, this equates to $24.07/GJ for Parkeston. The Net Ex Terminal distillate price is assumed to be $22.70/GJ, hence the assumed distillate road freight to Parkeston is $1.37/GJ.

D.4 Fuel consumption

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

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

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

		% site rating			
Temp	**Humidity**	**100%**	**50%**	**33%**	**25%**
15°C	30%	10584	11776	13066	14100

The minimum load position has been extracted from the sampled data and the corresponding heat rate at minimum determined from Table D- 2. This heat rate at this minimum, including the temperature variability, results in a normal distribution with a mean of 12.396 GJ/MWh and a standard deviation of 0.459 GJ/ MWh. The mean and the standard deviation has reduced slightly from the 2013 review due to changes in the assessed level and uncertainty of the minimum operating level based on the analysis of actual dispatch for the Parkeston units. The change in the assessed minimum operating level changes the average heat rate modelled even though the heat rate characteristics have not been changed since the 2013 review. The average minimum capacity level was increased in the 2014 review based on historical data for the 2013 calendar year.

D.5 Carbon cost for gas transportation

Unlike DBNGP, for the Gas to Goldfields Pipeline (GGP), there is no separately published level of emissions. Assuming maximum gas consumption for compressors of 490 TJ per year and applying the assumed gas combustion figure of 51.33 kg CO2-e/GJ, we obtain a total pipeline emission combustion figure of 25,151.7 t CO2-e. The pipeline is 1,378 km from Yarraloola to Kalgoorlie. Based on the transmission factor of 8.72 t CO2-e/km, the standard emission for the pipeline would be 12,016 t CO2-e, resulting in a total emissions of 37,168 t CO2-e. Dividing this quantity into the estimated contract capacity of 105.71 TJ/day gives a transport emission intensity of 0.963 kg CO2-e/GJ delivered. The corresponding carbon cost for gas transportation on the GGP is 2.4c/GJ as shown in Table D- 3.

Table D- 3 Analysis of gas transport emissions - GGP

	Units	**GGP**
Energy Consumption	TJ	490
Gas Combustion	t CO_2-e	25,152
Pipeline	t CO_2-e	12,016
Total	t CO_2-e	37,168
NGER Emissions	t CO_2-e	N/A
Transported	TJ	38,584
	TJ/day	106
Emissions	kg CO_2-e /GJ	0.963
c/GJ @ $25.40/tCO2e		2.4

Assuming 2.92 kg CO_2e/GJ for emissions from gas production, based on the Pinjar calculations described in Section 3.5.1, the overall Scope 3 emission rate for the Parkeston power station is 55.22[44] kg CO_2e/GJ, including emissions from gas production, transport and combustion in the power station. The emission cost is then added to the simulated fuel cost at the carbon price of \$25.40/tCO_2e.

D.6 Aero derivative gas turbines – LM6000

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

The variable O&M cost for aero derivative gas turbines is based upon a maintenance contract price of \$322.36/hour in March 2014 dollars as estimated and shown in the second column from the right in Table D- 4. These costs have been escalated from those used last year, as no new data could be established with confidence. The cost estimates change from last year's values was based on Australian price escalation and the change in the \$US dollar exchange rate. Jacobs SKM has applied economic time based discounting for the major overhaul components and the logistics costs split between scheduled and unscheduled maintenance to calculate a discounted cost of \$201.33/hour. This is escalated to \$205/hour at December 2014. This is slightly increased from \$203/hour in the 2013 review, due to price escalation and variations in the number of starts per year assumed.

Table D- 4 Basis for running cost of aero-derivative gas turbines —LM6000 (March 2014 dollars)

Overhaul Type	Number of hours trigger point for overhauls	Cost per Overhaul	Number in Overhaul Cycle	Cost per cycle	Cost per fired hour	Discounted Cost per fired hour
Preventative Maintenance	4,000 hrs, 450 cycles or annually, whichever first		17.836	\$285,665	\$5.71	\$5.71
Hot Section Rotable Exchange	25,000	\$4,359,738	1	\$4,359,738	\$87.19	\$44.54
Major Overhaul	50,000	\$6,086,843	1	\$6,086,843	\$121.74	\$62.18
Shipping of Parts, Travel, Living Expenses of Maintenance Personnel, Extra				\$2,026,105	\$40.52	\$24.91
Unscheduled Maintenance				\$2,822,766	\$56.46	\$56.46
Consumable Day-to-Day Maintenance (lube oil, air filters, etc)				\$376,799	\$7.54	\$7.54
			Total:	**\$15,957,916**	**\$319.16**	**\$201.33**

Source: Jacobs SKM data sourced from manufacturers and analysis of discounted value based on 28.7 starts/year

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

[44] Being 51.33 kg CO_2e/GJ for gas combustion, plus 0.963 kg CO_2e/GJ for transport, plus 2.92 kg CO_2e/GJ for gas production.

Table D- 5 shows the assessed variable O&M cost based on the historical operating regime for the aero derivative gas turbine since January 2013. The weighted average is $7.62/MWh. The variable O&M cost is more stable, so Jacobs SKM has not added uncertainty due to changes in starts per year or running hours.

Table D- 5 Assessed variable O&M cost for aero derivative gas turbine – LM6000

Aero Derivative Unit	Average Running Hours	Number of Starts / Year	Cost / Run	Average MWh per Run	Variable O&M Cost $/MWh
1	34.1	23.0	$6,992	823.9	$8.49
2	111.7	20.0	$22,899	2954.5	$7.75
3	204.7	29.0	$41,954	5615.9	$7.47
ALL UNITS	116.8	72.0	$25,493	3345.8	$7.62

It is considered that liquid firing of aero-derivative gas turbines doubles the frequency of the Hot Section Rotable Exchange every 12,500 hours. This increases the assessed discounted operating cost from $201/hour to $288/hour, a 43% increase.

D.7 Results

Table D- 6 compares the results for the aero-derivative gas turbines with the results shown above for the industrial gas turbines. It is evident that the costs remain substantially lower for the aero-derivative gas turbines.

Table D- 6 Analysis of dispatch cycle cost using average heat rate at minimum capacity

Sample	Aero Derivative – LM6000		Industrial Gas Turbine	
	Gas	Distillate	Gas	Distillate
Mean	$217.08	$278.18	$295.14	$505.65
80% Percentile	$234.63	$291.74	$332.46	$539.89
90% Percentile	$250.19	$299.09	$366.36	$567.61
10% Percentile	$190.01	$257.00	$236.74	$447.09
Median	$212.70	$278.29	$282.48	$501.09
Maximum	$307.47	$340.17	$541.05	$766.20
Minimum	$151.55	$225.83	$155.16	$388.32
Standard Deviation	$24.21	$17.09	$58.39	$50.93
Non-Fuel Component $/MWh				
Mean		$41.78		$80.38
80% Percentile		$42.94		$92.78
Fuel Component GJ/MWh				
Mean		10.413		18.734
80% Percentile		10.741		19.494
Equivalent Fuel Cost for % Value		$/GJ		
Mean		22.703		22.700
80% Percentile		23.163		22.936

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

In selecting the appropriate Maximum STEM Price, we may consider whether we should revise the pricing model to take account of observed dispatch patterns instead of using the average heat rate at minimum operating capacity. This would require a change to the Market Rules.

E.1 Methodology for market dispatch cycle cost method

The market dispatch cycle cost method was based on the following principles for output level during the dispatch cycle:

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

The use of the heat rate at minimum capacity is slightly conservative relative to results that would be expected from more detailed analysis based on typical operations. However, the impact on the Maximum STEM Price assessment in this review is minimal at $3/MWh rounding to the nearest integer.

E.2 Treatment of heat rates

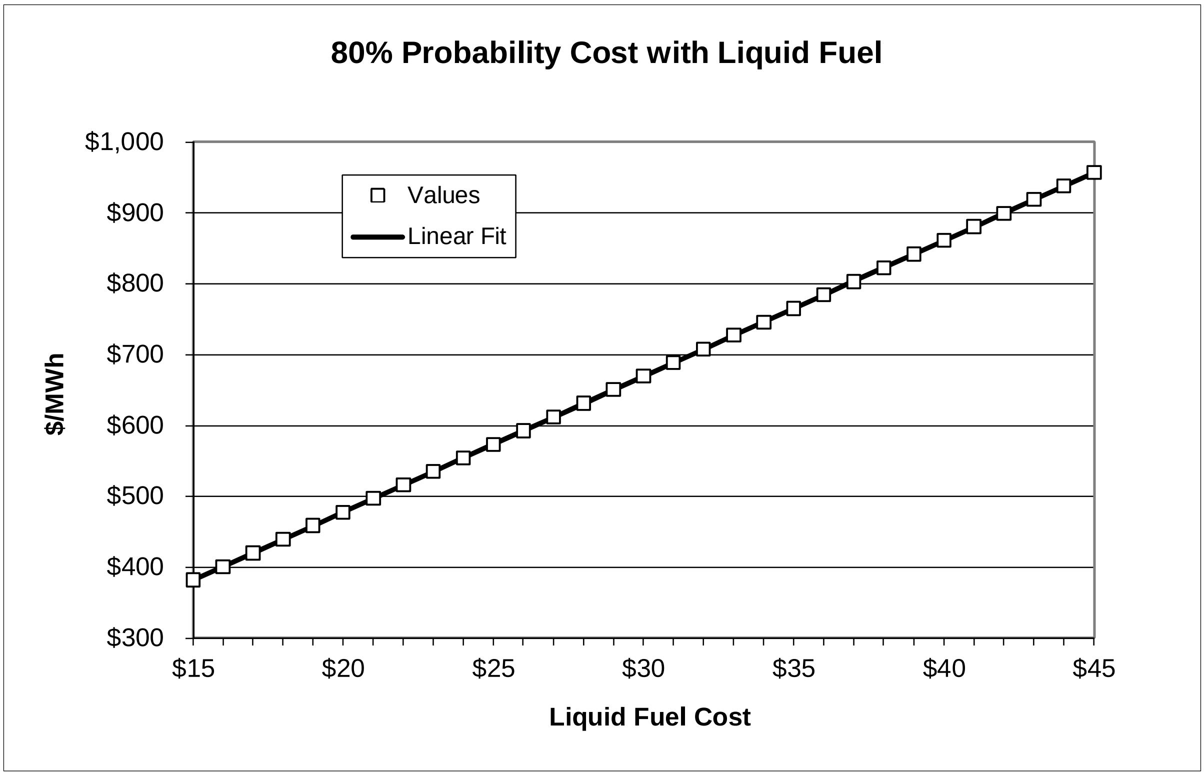
If we repeat the analysis of the Energy Price Limits, but develop the heat rates by using detailed dispatch modelling based on heat rate curves and probability distributions of capacity factor and maximum capacity derived from market data over the period from 1 January 2013 to 31 December 2013, with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

Table E.1 also shows the decomposition of the costs for distillate firing. The aero derivatives have a higher fuel cost due to their more remote location. The non-fuel and equivalent heat rate terms for distillate firing were derived from the 80% cumulative probability values of cost versus distillate price over the range between $15/GJ and $45/GJ as explained in section 2.5 for the 1,000 simulated values corresponding to each individual sample of cost. Again the relationship between the sampled values and the linear regression function was strong as shown in Figure E.1.

Table E.1 Analysis of dispatch cycle cost using market dispatch cycle cost method

Sample	Aero Derivative – LM6000		Industrial Gas Turbine	
	Gas	Distillate	Gas	Distillate
Mean	$211.48	$271.13	$289.59	$496.02
80% Percentile	$228.09	$284.90	$329.09	$533.81
90% Percentile	$243.24	$292.10	$364.99	$565.26
10% Percentile	$185.30	$250.67	$230.74	$434.87
Median	$207.27	$270.74	$278.06	$490.15
Maximum	$300.86	$326.81	$549.22	$762.31
Minimum	$150.85	$218.43	$147.37	$358.14
Standard Deviation	$23.59	$16.54	$59.86	$54.93
Non-Fuel Component $/MWh				
Mean		$40.92		$79.56
80% Percentile		$41.70		$93.89
Fuel Component GJ/MWh				
Mean		10.140		18.346
80% Percentile		10.445		19.173
Equivalent Fuel Cost for % Value $/GJ				
Mean		22.703		22.700
80% Percentile		23.285		22.944

Figure E.1 80% probability generation cost with liquid fuel versus fuel cost (using market dispatch cycle cost method)



E.3 Implications for margin with use of market dispatch cycle cost method

If we adopt these higher values, then the margin of the price cap over the expected cost is 13.4% for the Maximum STEM Price and 6.7% for the Alternative Maximum STEM Price if based on $22.70/GJ Net Ex Terminal distillate price, as shown in Table E.2 using rounded values. These margins reflect the current market and cost uncertainties[45].

Thus if we compare the assessed cost using the average heat rate at minimum capacity with the expected cost allowing for the dispatch cycles, then we obtain the comparison shown in Table E.3. This would provide an effective margin of up to 14.5% over the expected cost, which is the same as the required heat rate assumption (accounting for rounding error). The margin for the Alternative Maximum STEM Price is then 7.9% over the expected dispatch cycle cost.

Table E.2 Margin analysis (market dispatch cycle cost method)[46]

	Maximum STEM Price	Alternative Maximum STEM Price at $22.70//GJ[47]
Expected Cost	$290.00	$496.00
Market Dispatch Cycle Cost Based Price Cap	$329	$529.00
At Probability Level of	80%	80%
Margin	$39.00	$33.00
% Margin	13.4%	6.7%

Table E.3 Margin analysis with use of average heat rate at minimum capacity using market dispatch cycle cost for the expected cost

	Maximum STEM Price	Alternative Maximum STEM Price at $22.70/GJ
Expected Cost (Market Dispatch Cycle Cost)	$290.00	$496.00
Proposed Price Cap (Min Heat Rate)	$332.00	$535.00
At Probability Level of	80%	80%
Margin	$42.00	$39.00
% Margin	14.5%	7.9%

[45] Note that the expected value of $496/MWh for the Alternative STEM Price allows for the modelled uncertainty in the distillate price.
[46] Rounded to the nearest $/MWh
[47] Net Ex Terminal

Appendix F. Calculation of Energy Price Limits excluding carbon price

This Appendix recalculates the Energy Price Limits under the assumption that no carbon price is applicable during the 2014/15 financial year.

The revised calculation of limits is shown in Table F.1 based on the analysis shown in Table F.2.

The applicable Maximum STEM Price would be reduced from $332/MWh to $306/MWh.

The revised equation for the Alternative Maximum STEM Price would be

$58.71/MWh + 19.483 multiplied by the Net Ex Terminal distillate fuel cost in $/GJ

which at $22.70/GJ would give a revised Alternative Maximum STEM Price of $501/MWh, instead of $535/MWh.

Table F.1 Components of Energy Price Limits based on mean values (without a carbon price)

Component	Units	Maximum STEM Price	Alternative Maximum STEM Price	Source
Mean Variable O&M	$/MWh	$42.27	$42.27	Simulations
Mean Heat Rate	GJ/MWh	19.267	19.319	Simulations
Mean Fuel Cost	$/GJ	$12.19	$23.04	Simulations, fixed distillate price
Loss Factor		1.0312	1.0312	Western Power Networks
Before Risk Margin 6.20.7(b) [48]	$/MWh	$268.75	$472.63	Method 6.20.7(b)
Risk Margin	$/MWh	$37.25	$28.37	By difference from Energy Price Limits
	%	13.9%	6.0%	By ratio
Assessed Maximum Price	$/MWh	$306.00	$501.00	Table F.2

[48] Mean values have been rounded for the purpose of this calculation.

Table F.2 Cost analysis without carbon price

Sample	Aero Derivative – LM6000		Industrial Gas Turbine	
	Gas	**Distillate**	**Gas**	**Distillate**
Mean	$202.43	$259.80	$268.82	$472.58
80% Percentile	$219.92	$273.06	$306.41	$505.70
90% Percentile	$235.34	$280.52	$339.52	$534.06
10% Percentile	$175.97	$239.09	$210.63	$415.66
Median	$198.20	$259.86	$255.90	$467.73
Maximum	$288.52	$320.43	$512.88	$730.19
Minimum	$137.53	$208.04	$130.89	$357.52
Standard Deviation	$23.68	$16.72	$57.74	$49.93
Non-Fuel Component $/MWh				
Mean		$23.40		$47.30
80% Percentile		$23.98		$58.71
Fuel Component GJ/MWh				
Mean		10.413		18.734
80% Percentile		10.741		19.483
Equivalent Fuel Cost for % Value $/GJ				
Mean		22.703		22.700
80% Percentile		23.189		22.942