FINAL REPORT: 2017 BENCHMARK RESERVE CAPACITY PRICE FOR THE 2019–20 CAPACITY YEAR

FOR THE WHOLESALE ELECTRICITY MARKET

December 2016

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document under section 4.16 of the Wholesale Electricity Market Rules to provide information about the proposed final revised value of the 2017 Benchmark Reserve Capacity Price for the 2019–20 Capacity Year, as at the date of publication.

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EXECUTIVE SUMMARY

Each year, the Australian Energy Market Operator (AEMO) is required to determine the Benchmark Reserve Capacity Price (BRCP) in accordance with the Market Procedure: Maximum Reserve Capacity Price (Market Procedure)[1] for the Western Australian Wholesale Electricity Market (WEM).

The BRCP is used in the calculation of the maximum price that may be offered in a Reserve Capacity Auction, or as an input in the determination of the administered Reserve Capacity Price if an auction is not required. It aims to establish the marginal cost of providing one additional megawatt (MW) of Reserve Capacity in the relevant Capacity Year.

This report presents the outcome of the final determination of the BRCP for the 2017 Reserve Capacity Cycle. The 2017 BRCP applies for the 2019–20 Capacity Year, covering the period from 8:00 AM on 1 October 2019 to 8:00 AM on 1 October 2020.

The BRCP is calculated by undertaking a technical, bottom-up cost evaluation of the entry of a new 160 MW open cycle gas turbine (OCGT) generation facility in the South West interconnected system (SWIS) in the relevant Capacity Year. The broad methodology applied to determine the BRCP has not changed since the last five-yearly review completed in 2011, and includes the following costs:

- Building a 160 MW OCGT power station with inlet cooling.
- Acquiring land to develop and construct the power station.
- Connecting the power station to the transmission system.
- Building liquid fuel storage and handling facilities sufficient for the power station to operate for 14 hours at full capacity.
- Fixed operating and maintenance (O&M) costs associated with the power station and transmission facilities.
- A margin (Margin M) for legal, financing, insurance, approvals, other costs, and contingencies.
- The weighted average cost of capital (WACC).

The complete methodology used to determine the BRCP is outlined in the Market Procedure.

Proposed final value of the 2017 BRCP for the 2019–20 Capacity Year

AEMO proposes a final value of $149,800 per MW per year for the 2017 BRCP, 6.3% lower than the 2016 Maximum Reserve Capacity Price (MRCP)[2] of $159,800 per MW per year.

[1] Please note this Market Procedure has not been updated to reflect the amendments to the WEM Rules that commenced on 1 July 2016 as a result of the Electricity Market Review. The Maximum Reserve Capacity Price is now referred to as the Benchmark Reserve Capacity Price and all references to the Independent Market Operator should now refer to AEMO. The Economic Regulation Authority is now responsible for this Market Procedure, which is available at: https://www.erawa.com.au/cproot/14362/2/Market%20Procedure%20-%20Maximum%20Reserve%20Capacity%20Price.pdf.

[2] Please note that from this point the 2016 MRCP will be referred to as the 2016 BRCP.

Changes from the 2016 BRCP

Table 1 shows the year-on-year variation in the input parameters between the 2016 BRCP (for the 2018–19 Capacity Year) and the 2017 BRCP.

Table 1 Breakdown of variance between 2016 and 2017 BRCP

	Impact ($)	Impact (%)	BRCP (AU$)
2016 BRCP			**159,800**
Escalation factors	-5,100	-3.2	154,700
Power station cost	1,500	0.9	156,200
Margin M	-2,400	-1.5	153,800
Fixed fuel cost	-200	-0.1	153,600
Land cost	-100	-0.1	153,500
Transmission cost	1,500	0.9	155,000
WACC	-3,400	-2.1	151,600
Fixed O&M	-1,800	-1.1	149,800
2017 BRCP	**-10,000**	**-6.3**	**149,800**

The key changes from the 2016 BRCP are:

- Lower escalation factors have reduced the 2017 BRCP by 3.2%, largely due to lower commodity price and labour cost forecasts.
- The WACC has reduced the 2017 BRCP by 2.1%, due to a reduction in the real risk free rate.
- Margin M has reduced the 2017 BRCP by 1.5%, as a result of a reduction in environmental approval and permitting costs.

Public consultation

The draft BRCP report was published for consultation on 21 November 2016.

AEMO received submissions[3] from Tesla Corporation and Perth Energy. Both submissions questioned the WACC, due to the calculation of a negative risk free rate, which is a component of the WACC. More details on the submissions are provided in Chapter 4.

AEMO acknowledges these comments. However, AEMO notes it does not have the discretion to deviate from the prescribed methodology for calculating components of the WACC, as this is specified in the Market Procedure. AEMO will raise this issue, along with other methodology concerns discussed in Chapter 4, in the next five-yearly review of the Market Procedure by the Economic Regulation Authority (ERA) in 2017.

[3] See http://www.aemo.com.au/Stakeholder-Consultation/Consultations/Draft-Report-2017-Draft-Benchmark-Reserve-Capacity-Price-for-the-2019-20-Capacity-Year.

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1. INTRODUCTION

The Benchmark Reserve Capacity Price (BRCP) is used in the calculation of the maximum price that may be offered in a Reserve Capacity Auction. A Market Participant may offer up to 110% of the BRCP when submitting their Reserve Capacity Offer into the Reserve Capacity Auction. If an auction is not required, the BRCP is used as an input in the determination of the administered Reserve Capacity Price. The BRCP aims to establish the marginal cost of providing one additional megawatt (MW) of Reserve Capacity in the relevant Capacity Year.

This report presents the components and outcome of the final determination of the BRCP for the 2017 Reserve Capacity Cycle[4], which applies to the 2019–20 Capacity Year. The draft report was published on AEMO's website[5] on 21 November 2016. AEMO has considered all submissions received as part of the public consultation period prior to submitting the final 2017 BRCP to the Economic Regulation Authority (ERA) for approval in accordance with clause 4.16.7 of the Wholesale Electricity Market (WEM) Rules.

1.1 Overview of input parameters

The BRCP is calculated by undertaking a technical, bottom-up cost evaluation of the entry of a new 160 MW open cycle gas turbine (OCGT) generation facility in the South West interconnected system (SWIS) during the relevant Capacity Year. The broad methodology and fixed input parameters used to determine the BRCP have not changed since 2011 due to the deferral of the five yearly review of the Market Procedure: Maximum Reserve Capacity Price (Market Procedure) to 2017.[6]

In determining the 2017 BRCP, AEMO used publicly available information including advice from independent consultants, Western Power, and the Western Australian Land Information Authority (Landgate).

The organisations and the input parameters they provided are shown in Table 2.

Table 2 Consultants and agencies

Organisation	Cost estimates provided
GHD (Australia)	Power station capital costs and relevant escalation factors Margin for legal, approval, financing, insurance, other costs, and contingencies Fixed fuel costs Generation O&M costs and relevant escalation factors Switchyard O&M costs and relevant escalation factors Transmission line O&M costs and relevant escalation factors
Landgate	Land costs
PricewaterhouseCoopers (PwC)	Debt risk premium (DRP)
Western Power	Transmission connection costs and relevant escalation factors

Throughout this report, cost and price estimates are expressed in Australian dollars, unless otherwise specified.

4 See http://wa.aemo.com.au/home/electricity/reserve-capacity/reserve-capacity-timetable-overview.

5 See http://www.aemo.com.au/Stakeholder-Consultation/Consultations/Draft-Report-2017-Draft-Benchmark-Reserve-Capacity-Price-for-the-2019-20-Capacity-Year.

6 Please note this Market Procedure has not been updated to reflect the amendments to the WEM Rules that commenced on 1 July 2016 as a result of the Electricity Market Review. The Maximum Reserve Capacity Price is now referred to as the Benchmark Reserve Capacity Price and all references to the Independent Market Operator should now refer to AEMO. The Economic Regulation Authority is now responsible for this Market Procedure, which is available at: https://www.erawa.com.au/cproot/14362/2/Market%20Procedure%20-%20Maximum%20Reserve%20Capacity%20Price.pdf.

1.3 Supporting documentation

The following related documents are available on AEMO's website[7]:

- 2017 BRCP calculation spreadsheet, draft report version.
- 2017 BRCP calculation spreadsheet, final report version.
- GHD report, *2017 Benchmark Reserve Capacity Price for the South West Interconnected System* (20 October 2016).
- PwC letter, *Determining the debt risk premium using the ERA's 'Bond Yield Approach'* (25 October 2016).
- PwC letter, *Determining the debt risk premium using the ERA's 'Bond Yield Approach'* (5 December 2016).
- Landgate report, *Land values for the 2017 Benchmark Reserve Capacity Price* (16 September 2016).
- Weighted Average Cost of Capital (WACC) parameter calculation spreadsheet, draft report version and final report version.
- Western Power report, Total Transmission Cost Estimate for the Benchmark Reserve Capacity Price for 2019/20 (14 October 2016).

[7] See http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Benchmark-Reserve-Capacity-Price.

2. 2017 BRCP INPUT PARAMETERS

2.1 Escalation factors

The 2017 BRCP calculation is based on a theoretical power station that would commence operation on 1 October 2019. Costs have been determined as at 2016 and have been escalated to 2019.

Depending on the type of component cost being estimated, different escalation factors are used. This is summarised in Table 3.

Table 3 Cost escalation forecast

Escalation factor	Component costs applied to	Source and methodology
Power station capital cost	Power station capital cost	The methodology is derived by GHD and summarised in their report. The determination involves sourcing information from the Australian Bureau of Statistics, London Metal Exchange, Reserve Bank of Australia, and the CME Group.
Generation O&M cost	Generation O&M cost	
Connection asset O&M cost	Switchyard O&M cost Transmission line O&M cost	
Consumer Price Index (CPI)	Asset insurance O&M cost Fixed network access and ongoing O&M charges Fixed fuel cost Land cost	A general measure of price inflation for all Australian households is forecast by the Reserve Bank of Australia (RBA). Where a forecast range is provided, the mid-point is applied. For the first year outside of the RBA's forecast horizon, the average of the previous year's forecast and the mid-point of the RBA's target for inflation is used. For all periods beyond, the mid-point of the RBA's target for inflation is used.
Transmission connection cost	Transmission connection cost	This is estimated using the average change over five years as per clause 2.4.2 of the Market Procedure. However, as five years of actual data was not available for the 2017 BRCP the escalation rate is averaged over a period for which equivalent data is available. Western Power provides these escalation factors.

The escalation factors applied to the 2017 BRCP are listed in Table 4.

Table 4 Escalation factors by financial year

Escalation factor	2016–17	2017–18	2018–19	2019–20
Power station capital cost	-1.01%	2.51%	1.96%	2.81%
Generation O&M cost	2.58%	1.85%	2.33%	2.33%
Connection asset O&M cost	1.60%	1.60%	1.90%	1.90%
CPI	2.00%	2.00%	2.25%	2.50%
Transmission connection cost	-0.02%	-0.02%	-0.02%	-0.02%

All escalation factors have decreased from the 2016 Maximum Reserve Capacity Price (MRCP)[8], except for the transmission connection cost escalation. Persistent low commodity prices, in particular for copper and steel, have reduced the power station capital cost escalation factor. Slow growth in labour costs associated with subdued activity in the resources and energy sectors has lowered the generation O&M and connection asset O&M escalation factors.

[8] Please note that from this point the 2016 MRCP will be referred to as the 2016 BRCP.

2.2 Capital costs

2.2.1 Power station capital cost (PC)

GHD used the Siemens SGT5-2000E (33MAC) 173 MW[9] OCGT as the reference equipment to determine the power station capital cost component of the 2017 BRCP, consistent with the 2016 BRCP. The unit is considered to be the most appropriate machine available to meet the criteria for the BRCP calculation.[10] GHD used version 25 of Thermoflow's GTPro[11] model to evaluate the plant equipment, engineering, procurement, and construction capital costs. Estimated costs were referenced against similar completed projects in Australia where possible.

The total capital cost was escalated to 1 April 2019 using the power station capital cost escalation factor.

The proposed final value of **PC = $810,229 per MW**.

The estimated PC has decreased by 2.9% (a reduction of around $25,000) from the 2016 BRCP, due to lower commodity prices and labour costs. This estimate has not changed from the draft report.

2.2.2 Capacity Credit (CC) allocation

GHD used GTPro to model the output of the 160 MW reference generator by adjusting the expected performance of the equipment to site conditions at Muja power station (41°C, 30% relative humidity, and 217 metres above sea level). This estimate has not changed from the draft report.

The proposed final value of **CC = 148.5 MW**.

2.2.3 Legal, approval, financing, insurance, other costs, and contingencies (M)

'Margin M' covers legal, approval, financing, insurance, other costs, and contingencies during the project construction phase. It was estimated from similar costs associated with recent, comparable developments from GHD's data bank, excluding any project-specific abnormal costs. The costs were scaled to the reference equipment where relevant. Margin M was then added as a fixed percentage of the capital cost of developing the power station.

The proposed final value of **M = 17.19%**.

The reduction in Margin M from 20% in the 2016 BRCP is due to a significant reduction in environmental permit and approval costs, which is now based on a less complex works approval assessment. This estimate has not changed from the draft report.

2.2.4 Land costs (LC)

Land valuations were made for the following six regions where development of a power station in the SWIS is most likely:

- Collie.
- Kalgoorlie.
- Kemerton Industrial Park.
- Kwinana.
- North Country (Eneabba and Geraldton).
- Pinjar.

9 This is the nameplate rating provided by GTPro.

10 There is currently no generator available on the market that matches the specifications of the Market Procedure. As a result, GHD has scaled the estimation for the 173 MW Siemens unit to represent the expected configuration of the 160 MW generator specified in the Market Procedure.

11 Further information is available at: http://www.thermoflow.com/combinedcycle_PCE.html.

Landgate assessed hypothetical land sites for each region in or near existing industrial estates for land that would be suitable for the development of a power station. Valuations were completed as at 30 June 2016 and exclude transfer duty (previously known as stamp duty). AEMO has added the applicable transfer duty to the land parcel cost using the Office of State Revenue's online calculator.[12]

AEMO calculated the average of the six valuations and escalated this to 1 April 2019 using the CPI escalation factor. The size of the land parcels for all regions was three hectares, except for Kemerton, where the minimum land size is five hectares.

The proposed final value of **LC = $2,430,526**.

The LC estimates decreased by 8.5% from the 2016 BRCP. The continued slowdown in the WA economy, driven by a weakening resources sector, has reduced demand for industrial land, resulting in lower sales and land prices. This affected the land valuations of Geraldton, Kwinana, and Pinjar regions. This estimate has not changed from the draft report.

2.2.5 Transmission connection cost (TC)

TC is based on a weighted average of the capital contributions of generators connecting to the SWIS over the previous five years. Estimates are based on actual connection costs and access offers identified by Western Power through its confidential database.

As there is no actual project data available in the five-year window, Western Power estimated the shallow connection cost in accordance with the methodology described in the Market Procedure. The methodology includes the estimation of capital costs such as the procurement, installation and commissioning of the substation, and easement costs. Western Power provided an independent audit report to verify the accuracy of the estimates on the basis that the underlying data is commercial in-confidence and therefore cannot be published.

Shallow connection cost estimates include construction of a substation, 2 kilometres (km) of overhead line to the power station, and an overhead line easement. AEMO provides easement costs to Western Power for use in estimating shallow connection costs. AEMO's easement cost estimate is based on the following assumptions:

- The easement is 12 hectares (2 km long and 60 metres wide).
- A new generator may not need to purchase the entire 12 hectares, instead securing easement rights for some or all of the land. AEMO estimates easement costs to be half of the land value.
- The land value includes transfer duty.

Easement costs have decreased by 7.9% from the 2016 BRCP, due to a fall in land values in the Geraldton, Kwinana, and Pinjar regions (see Section 2.2.4 for more information).

The shallow connection costs have decreased from $22,983,826 to $22,558,523 for the 2017 BRCP.

The proposed final value of **TC = $175,444 per MW**.

No escalation factors have been applied, as Western Power has already escalated the TC estimate to 1 April 2019.

The TC estimate has increased from the 2016 BRCP value of $160,280. Despite the decrease in shallow connection costs and easement costs the overall TC estimate has increased by 9.5%. This is due to the increase in the other components of the TC estimate provided by Western Power that AEMO does not have visibility into due to confidentiality reasons. This estimate has not changed from the draft report.

[12] Available at: https://rol.osr.wa.gov.au/Calculators/faces/Calculators?_afrLoop=247790592985840&_afrWindowMode=0&_adf.ctrl-state=re8l3w9ui_4.

2.2.6 Fixed fuel cost (FFC)

FFC is the cost associated with developing and constructing onsite liquid fuel storage and supply facilities, and supporting infrastructure, including the initial cost of filling the tank with diesel to a level sufficient for 14 hours of operation. GHD provided an estimate of FFC as of 30 June 2016, which is escalated to 1 April 2019 using the CPI escalation factor. The cost of diesel includes delivery and excise but excludes GST.

The proposed final value of **FFC = $6,803,924**.

The FFC estimate decreased by 4.0% from the 2016 BRCP. This is largely associated with a decrease in the price of delivered diesel to $0.66 per litre (10.8% lower than the 2016 BRCP), as a result of low international oil prices, the slightly lower gross output of the reference equipment, and a higher fuel to energy efficiency rating. Therefore, the cost of the first fill of the storage tank has fallen to $434,000, compared to $600,300 in the 2016 BRCP. This estimate has not changed from the draft report.

2.2.7 Weighted average cost of capital

The WACC is determined by using the Capital Asset Pricing Model to estimate the costs of equity and debt. The debt risk premium (DRP) was estimated by PwC, while the risk free rate and expected inflation components of the WACC are calculated using information available from the RBA's website.[13] The nominal risk free rate was determined using observed yields of Commonwealth Government bonds, while the DRP was derived using observed yields of corporate bonds. A corporate tax rate of 30% was assumed.

Appendix A provides more detail on the steps for estimating the WACC.

Risk free rate of return methodology

The nominal risk free rate was calculated from the annualised yield of a selection of Commonwealth Government bonds with maturity dates of roughly 10 years. The rate was estimated using a 20-day average from market observations ending on 30 November 2016.

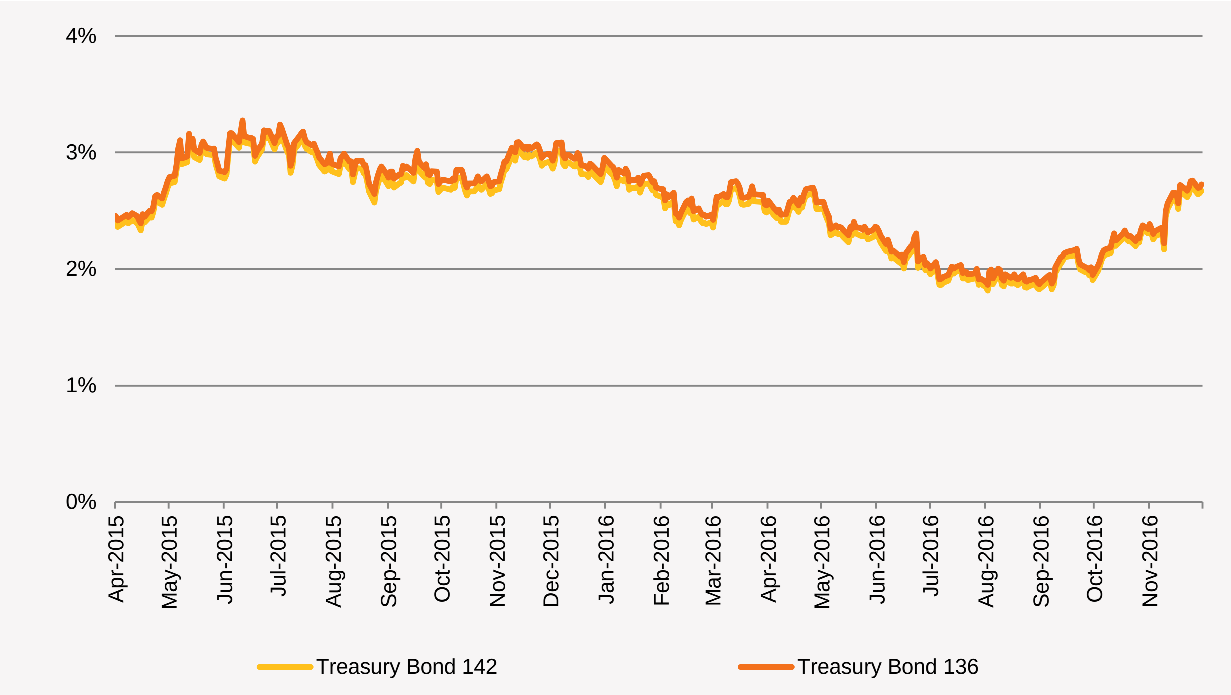
Commonwealth Government bond yields have fallen since the 2016 BRCP in line with a decline in global bond yields, as shown in Figure 1.

The nominal risk free rate calculated from these bonds is 2.57%, a decrease from 2.92% in the 2016 BRCP.

The nominal risk free rate has increased from the draft report value of 2.12%, due to a slight increase in bond yields in November.

[13] See http://www.rba.gov.au/statistics/tables/ and http://www.rba.gov.au/publications/smp/index.html.

Figure 1 Commonwealth Government bond yields, April 2015 to November 2016



The nominal rate was then adjusted for inflation to determine the real risk free rate of return. As per the Market Procedure, AEMO is required to use the RBA's inflation forecasts or the mid-point of the RBA's target inflation range outside of the forecast period. Based on the RBA's forecasts and target of 2% to 3%, the expected rate of inflation is 2.39%. The RBA's forecast of inflation has not changed since the publication of the draft report.

The above parameter values have resulted in a real risk free rate of 0.18%. This is an increase from the negative risk free rate of -0.26% calculated in the draft report, as a result of an increase in Commonwealth Government bond yields.

AEMO notes that a real risk free rate of 0.18% is not reflective of current Australian market conditions, as it implies that riskier assets are generating low returns. The lower than expected real risk free rate is due to a high expected rate of inflation. If the expected rate of inflation is replaced with the current rate of inflation of 1.3%,[14] the real risk free rate of return is 1.25%. AEMO considers this to be a better representation of the current market as the All Ordinaries stock index has increased by 6.8% between January and October 2016, and the Standard and Poors/Australian Stock Exchange 200 index has increased by 6.2%.[15] Both stock indexes represent the expected return from a portfolio of stocks with an average risk premium on the Australian market. However, AEMO has no discretion to deviate from the methodology stipulated in the Market Procedure.

In addition, AEMO notes the ERA calculated a negative real risk free rate in the *Determination on the 2016 Weighted Average Cost of Capital for the Freight and Urban Railway Networks, and for Pilbara railways*.[16] This was due to an assumed long-term inflation rate of 2.5%, which the ERA determined was not representative of inflation expectations implicit in prices observed in the market. Hence the ERA deviated from their methodology and used an inflation rate of 1.74%, calculated from Treasury Bonds and Treasury Indexed Bonds.

[14] Australian Bureau of Statistics. 2016. *Consumer Price Index, Australia, June 2016*. Available at: http://www.abs.gov.au/AUSSTATS/abs@.nsf/mf/6401.0. Viewed: 9 December 2016.
[15] See http://www.asx.com.au/about/historical-market-statistics.htm for more information.
[16] Available at https://www.erawa.com.au/cproot/14527/2/Att%201%20Rail%20-%20WACC%20Final%20Determination%20of%20WACC%202016%2061%202017.PDF.

Debt risk premium methodology

The Market Procedure requires AEMO to determine the methodology to estimate the DRP which in the opinion of AEMO is consistent with currently accepted Australian regulatory practice.

The ERA has recently adopted a modified bond yield approach to estimate the DRP for *the Final Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution Systems.*[17] AEMO considers this revised methodology to be representative of current accepted Australian regulatory practice, and the DRP has been calculated accordingly. AEMO notes that the revised methodology was generally supported by Market Participants during the consultation period for the 2016 BRCP.

The revised bond yield approach uses a larger sample of bonds issued by Australian utilities on Australian and international markets to estimate a bond yield curve to calculate a 10-year DRP. PwC estimated the DRP at 2.22% from market observations ending on 25 November 2016. The final DRP estimate has decreased from the draft report value of 2.32%, due to Commonwealth Government bond yields increasing by a greater margin than corporate bond yields.

Capital Asset Pricing Model results

The proposed final value of the **WACC (real terms) = 5.29%**.

This is lower than the WACC (real terms) of 5.69% used in the 2016 BRCP. This is a direct result of the low real risk free rate of return estimated in accordance with the Market Procedure.

AEMO notes that if the current rate of inflation is used in the estimation of the real risk free rate of return, the WACC (real terms) is 6.43%. Using a WACC of 6.43% results in the proposed final BRCP increasing by 6.7% ($159,800), which is the same as the 2016 BRCP.

Market Participants queried the WACC methodology outlined in the Market Procedure during the 2017 BRCP consultation period and previous BRCP determinations. AEMO has compiled a list of all other concerns regarding the methodology (see Chapter 4) and will provide this information to the ERA for consideration during the review of the Market Procedure tentatively scheduled for 2017.

2.3 Operating and maintenance costs

2.3.1 Generation O&M costs

Generation O&M costs assume that the OCGT plant is based on a single gas turbine capable of delivering a nominal 160 MW output, using diesel fuel, with a 30-year operating life and a 2% capacity factor. Gas connection costs are therefore not considered. An allowance for balance of plant (service of pumps, fire systems etc.) has been included.

A 15-year annuity is calculated based on individual component costs as at June 2016, which are derived from similar recent OCGT projects. These costs are then escalated to 1 October 2019 using the generation O&M escalation factor.

The proposed final value of **generation fixed O&M costs = $14,572 per MW per year**.

The estimated O&M cost decreased by 10.8% from the 2016 BRCP. This is due to the decrease in the generation O&M escalation factor (see Section 2.1 for more detail). This estimate has not changed from the draft report.

2.3.2 Switchyard O&M costs

Switchyard O&M costs were calculated from the isolator on the high voltage side of the generator transformer and do not include any generator transformer or switchgear associated costs.

[17] Available at https://www.erawa.com.au/cproot/13880/2/GDS%20-%20ATCO%20-%20AA4%20-%20Amended%20Final%20Decision%20-%20PUBLIC%20VERSION.PDF.

A bottom-up approach was used to estimate the switchyard costs, based on the annual charge for the connection infrastructure. The cost estimate included labour, machinery parts, and general overheads incurred during routine maintenance, which occurs one week per year on average.

The 330 kV switchyard was assumed to have an average asset life of 60 years. A 15-year annuity was calculated based on the cost estimate as at June 2016, which was then escalated to 1 October 2019 using the connection O&M escalation factor.

The proposed final value of **switchyard O&M costs = $528 per MW per year**.

The switchyard O&M cost estimate increased by 7.3% from the 2016 BRCP. GHD considers the 2016 cost estimate to be undervalued. However, a comparison of the costs is not possible as the previous consultant used to develop the 2016 BRCP provided limited details on their switchyard assumptions. AEMO has ensured that GHD completed a bottom-up technical approach when setting their assumptions. This estimate has not changed from the draft report.

2.3.3 Transmission line O&M costs

The new transmission line was assumed to be a single circuit 330 kV construction with two conductors per phase, and was assumed to have an average asset life of 60 years. The rating of the line was selected to facilitate the transport of up to 200 MVA (power factor of 0.8). A bottom-up approach was used to estimate the transmission costs based on the annual charge for the connection infrastructure.

The cost estimate included labour, machinery parts, and general overheads incurred during routine maintenance. A 15-year annuity was calculated based on the cost estimates as at June 2016, which was then escalated to 1 October 2019 using the connection O&M escalation factor.

The proposed value of **transmission line O&M costs = $32.74 per MW per year**.

The transmission line O&M estimate increased significantly from the 2016 BRCP value of $9.47 per MW per year. GHD considers the 2016 cost estimate to be undervalued, and have assumed that a line inspection would be carried out over a two-day period each year that requires hiring a scissor lift. This estimate has not changed from the draft report.

2.3.4 Asset insurance costs

The fixed O&M component included annual insurance costs to cover power station asset replacement, business interruption, and public and products liability insurance. AEMO has obtained advice on insurance costs from an independent broker to calculate insurance premiums. The broker prefers to remain anonymous to protect its competitive position.

Premiums were calculated as follows:

- Asset replacement insurance was calculated as 0.26% of the limit of liability, as advised by the broker. The limit of liability was determined as the sum of the capital construction cost and value of fuel.
  - The capital cost and value of fuel were estimated as: PC x (1 + M) x CC + FFC.
  - AEMO calculated asset replacement insurance as $430,370 per year.
- Business interruption insurance included coverage for the potential refund liability for the facility for two years. While a construction period of one year was assumed in the application of WACC, a period of time would be required prior to commencement of construction work following a loss event (for example, for service procurement, building approvals, and any demolition or clearing works). The refund mechanism in the WEM Rules means that a Market Participant may be required to refund two years' worth of capacity payments in less than 15 months.
- AEMO calculates business interruption insurance as **$129,590 per year**.

- Public and products liability insurance is estimated as **$114,407 per year**. This liability includes 10% transfer duty for a limit of $50 million for any one occurrence, as required by Western Power in an Electricity Transfer Access Contract.
- A cost of **$20,952 per year** for an annual insurance site survey is included.

The premium estimates are consistent with the assumption that the insurance covers:

- A newly constructed generation facility with on-site diesel storage.
- A facility located in a rural region of the SWIS with no cyclone risk.
- Machinery breakdown.
- Deductibles of $25,000 to $50,000 for public and products liability insurance, $500,000 for property damage, and 60 days for business interruption insurance.

Estimated insurance costs were escalated where necessary to 1 October 2019 using the CPI escalation factor.

The proposed final value of Asset insurance costs = **$4,791 per MW per year**.

The insurance cost estimates have increased by 2.9% from the 2016 BRCP. This is due to an increase in business interruption, asset replacement, and public and products liability insurance premiums, in line with global energy sector insurance markets. Changing weather patterns and increased risk of natural disasters is a cause for concern among insurers. The recent South Australian state-wide power outage in September 2016 has led to Australian insurers adopting a cautious stance on liability cover for power stations.

This estimate has increased by 0.5% from the draft report, as a result of the overall increase of the proposed final BRCP.

2.3.5 Fixed network access and on-going charges

Network access charges were estimated using Western Power's network access tariffs (Price List) data from the 2016–17 Price List approved by the ERA.[18] The relevant tariff that applies to generation facilities is the Transmission Reference Tariff 2.

As network access charges vary by location, AEMO considered the list of six regions outlined in the Market Procedure and applied the unit price for the most expensive location. Muja Power Station substation "Use of System" is the most expensive location and hence was selected as the base tariff input for the estimation of the fixed network access charges. The other two input component costs included control system and transmission metering service charges. Total annual costs per MW were calculated as at July 2016 and have been escalated by CPI to 1 October 2019.

The proposed final value of **Fixed network access costs = $10,219 per MW per year**.

The fixed network access cost estimates have decreased by 7.9% from the 2016 BRCP, due to a fall in the use of system charges. This estimate has not changed from the draft report.

Due to the Western Australian Government's Electricity Market Review[19] , the 2016 BRCP report made reference to the removal of TUOS charges, as requested by the Public Utilities Office (PUO). Under the assumption that the regulation of Western Power's networks would be transferred to the National Electricity Rules on 1 July 2018, the 2016 BRCP report modelled the impact of the removal of TUOS charges on the final BRCP value. However, given the bills[20] related to this transfer are now unlikely to proceed, the PUO has requested AEMO to not make any reference to the removal of TUOS charges in the 2017 BRCP.

[18] Available at https://www.erawa.com.au/cproot/14244/2/2016-17%20Price%20List.pdf.
[19] More information available at: https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Network_Regulation.aspx.
[20] The National Electricity (Western Australia) Bill 2016 is available at: http://www.parliament.wa.gov.au/Parliament/Bills.nsf/003B5D7348CF977C48257FD9003EBCFE/$File/Bill189-1.pdf.

3. PROPOSED VALUE OF THE 2017 BRCP

3.1 Annualised Capital Costs (ANNUALISED_CAP_COST)

The theoretical total capital cost (CAP_COST) of building a new power station in the SWIS and connecting it to the grid is estimated from the component costs determined in Section 2.2. This is expressed as:

$$CAP\_COST = \left((PC \times (1+M) + TC) \times CC + FFC + LC\right) \times (1+WACC)^{\frac{1}{2}}$$

The proposed final value of **CAP_COST = $180,893,141**.

CAP_COST is then annualised over a 15-year period using the WACC.

This produces an **ANNUALISED_CAP_COST = $17,776,436 per year**.

The annualised capital cost estimate decreased by 7.2% from the 2016 BRCP.

The estimate has increased by 3.5% from the draft report due to an increase in the WACC.

3.2 Annualised Operating and Maintenance Costs (ANNUALISED_FIXED_O&M)

The theoretical annualised fixed O&M cost is the sum of individual O&M components calculated in Section 2.3. This is expressed as:

ANNUALISED_FIXED_O&M = generation O&M costs + switchyard O&M costs + transmission line O&M costs + asset insurance costs + fixed network access costs and on-going charges

Depreciation is omitted, as it forms part of a regulated utility's annual revenue entitlement.

The proposed final value of **ANNUALISED_FIXED_O&M = $30,143 per MW per year**.

The annualised fixed O&M cost estimate decreased by 7.5% from the 2016 BRCP.

The estimate has increased by 0.1% from the draft report due to a slight increase in insurance costs.

3.3 BRCP Calculation

The BRCP is estimated by summing the annualised fixed O&M and annualised capital expenditure on a per MW basis. This is expressed as:

$$BRCP = ANNUALISED\_FIXED\_O\&M + \frac{ANNUALISED\_CAP\_COST}{CC}$$

The proposed final value of the 2017 BRCP is estimated to be $149,849 which is then rounded to the nearest $100.

The proposed final **BRCP = $149,800 per MW per year**.

The proposed final 2017 BRCP is 6.3% lower than the 2016 BRCP. This estimate is 2.7% higher than the value proposed in the draft report as a result of the updated WACC parameters.

An overview of the variation of the components of the 2016 BRCP and 2017 BRCP is listed in Table 5.

Table 5 BRCP components for 2016 and 2017

	2016 BRCP	2017 BRCP	Unit
BRCP	159,800	149,800	AU$/MW/year
ANNUALISED_FIXED_O&M	32,582	30,143	AU$/MW/year
Generation O&M cost	16,330	14,572	AU$/MW/year
Switchyard O&M cost	492	528	AU$/MW/year
Transmission line O&M cost	9.47	32.74	AU$/MW/year
Asset insurance cost	4,654	4,791	AU$/MW/year
Fixed network access and on-going charges	11,096	10,219	AU$/MW/year
CAP_COST	189,810,126	180,893,141	AU$
Power station cost	834,782	810,229	AU$/MW
Margin M	20.00	17.19	%
Transmission cost	160,280	175,444	AU$/MW
Capacity credit allocation	150.5	148.5	MW
Fixed fuel cost	7,089,948	6,803,924	AU$
Land cost	2,656,499	2,430,526	AU$
WACC	5.69	5.29	%
ANNUALISED_CAPCOST	19,149,362	17,776,436	AU$/year
Term of finance	15	15	Years

The changes between the 2016 and 2017 BRCP values by input parameter are shown in Table 6. Most of the changes relate to a decrease in the WACC and escalation factors.

A detailed breakdown of the historical BRCP since market start is provided in Appendix B.

Table 6 Breakdown of variance between 2016 and 2017 BRCP

	Impact ($)	Impact (%)	BRCP (AU$)
2016 BRCP			**159,800**
Escalation factors	-5,100	-3.2	154,700
Power station cost	1,500	0.9	156,200
Margin M	-2,400	-1.5	153,800
Fixed fuel cost	-200	-0.1	153,600
Land cost	-100	-0.1	153,500
Transmission cost	1,500	0.9	155,000
WACC	-3,400	-2.1	151,600
Fixed O&M	-1,800	-1.1	149,800
2017 BRCP	**-10,000**	**-6.3**	**149,800**

4. STAKEHOLDER SUBMISSIONS AND METHODOLOGY CONCERNS

The 2017 BRCP draft report and supporting documents were published for public consultation on 21 November 2016. Market Participants and other industry stakeholders were advised of the publication and an announcement was published in the West Australian on 22 November 2016.

AEMO received submissions from Tesla Corporation and Perth Energy. A summary of the issues raised in the submissions and AEMO's response is in Table 7.

AEMO has also compiled a list of concerns identified during the determination of the 2017 BRCP in Table 8.[21] AEMO will discuss these methodology concerns and submissions raised by Market Participants with the ERA during the next major review of the Market Procedure, due in 2017.

[21] List is not exhaustive.

Table 7 AEMO's responses to issues raised in public consultation

Submitter	Component	Comment	AEMO's response
Tesla Corporation	PC – Reference equipment	Tesla Corporation notes that the benchmark generator (160 MW) should be reduced to reflect the size of the units that have recently been installed in the SWIS (30 to 40 MW). Tesla Corporation considers that the size of such units is more likely to reflect future growth of peak demand in the WEM.	The methodology prescribed in the Market Procedure currently requires the theoretical reference power generating station to be a 160 MW OCGT. AEMO notes Tesla Corporation's concern regarding the size of the reference generator, and has raised this methodology issue in Appendix C of the draft report. AEMO will raise this issue with the ERA during the next five-yearly methodology review due in 2017.
Tesla Corporation	PC – OCGT capital cost estimate	Tesla Corporation notes that the total engineering, procurement and construction costs of a 160 MW nominal generator are derived from scaling down costs for plant equipment, civil works, mechanical and electrical works for a 178 MW generator. Tesla Corporation agrees that some of these costs can be scaled down (e.g. size of turbine blades), but many of these costs are fixed and not scalable. Tesla Corporation requests that non scalable cost elements should be kept at the 178 MW cost levels.	Table 13 of GHD's report lists which costs are treated as fixed and which are treated as scalable. GHD have confirmed that they view this as an appropriate methodology, consistent with that used for previous years' BRCP calculations. GHD has confirmed that costs for the items identified as scalable in Table 13 of GHD's report are directly affected by the size or capacity of the generating unit. For example, civil works are scalable as they are driven by the size and weight of the generating unit while electrical works are scalable as electrical plant and equipment is driven by the equipment rating and size of the generating unit. AEMO considers that the scaling approach applied by GHD represents the best application of the current Market Procedure, in the absence of recent projects for comparative purposes.
Tesla Corporation	WACC – equity beta	Tesla Corporation considers that the current value for the equity beta is too low, given the recent volatile operating market for electricity generation assets in WA. An equity beta of more than 1 should be considered, which is consistent with WACC determinations by the Independent Pricing and Regulation Tribunal (IPART) in New South Wales. Tesla Corporation suggests AEMO use an equity beta of 1.05 instead of 0.83, which is the mid-point range recommended by IPART (0.95 to 1.15 for electricity generators).	The equity beta value used in the derivation of the WACC is one of the five-yearly components described in the Market Procedure. The review of these estimates was last carried out in October 2011. AEMO considers that the WACC calculation should be reviewed during the next five-yearly BRCP methodology review due in 2017.

Submitter	Component	Comment	AEMO's response
Tesla Corporation	WACC – risk free rate of return	Tesla Corporation notes that using a risk free bond rate with a duration of 10 years is different to that used by the ERA. The ERA commonly uses a five-year rate which aligns with the regulatory period for electricity and gas distribution assets. A 10-year rate may be appropriate to new entrant generators but not to compensating existing generation. Existing generation is unlikely to have access to 10-year financing and will have locked in financing in prior years at a different rate. As such, the current methodology exposes existing generation to on-going exposure to debt markets. Tesla Corporation notes that the calculation of a negative risk free rate in the draft report makes no sense given other sectors of the Australian economy are making significant real returns. Tesla Corporation suggests AEMO should propose a change to the Market Procedure as the methodology for calculating the real risk free rate is flawed.	The methodology prescribed in the Market Procedure currently requires AEMO to calculate a nominal risk free rate on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years. The methodology then requires AEMO to adjust the nominal risk free rate by applying the RBA's forecast and target range of inflation. AEMO considers that use of a risk free bond rate with a duration of 10 years should be reviewed during the next five-yearly BRCP methodology review due in 2017. AEMO notes that the calculation of a negative risk free rate in the draft report was discussed with the ERA and raised as a point of concern in the draft and final report. AEMO considers that given the next five-yearly BRCP methodology review will occur in 2017, it will be more practical to raise all methodology concerns at that time. Market Participants may propose a Market Procedure change to the ERA in accordance with clause 2.10.2 of the WEM Rules.
Perth Energy	WACC – risk free rate of return	Perth Energy notes that the calculation of a negative risk free rate in the draft report is divorced from reality and encourages AEMO to raise this as a significant matter with the ERA.	AEMO notes that during the preparation of the draft report the calculation of a negative risk free rate was raised with the ERA. AEMO considers that the WACC calculation should be reviewed during the next five-yearly BRCP methodology review due in 2017.

Table 8 Methodology concerns raised by AEMO

Component	Comment
Fixed O&M – Insurance	The methodology prescribed in the Market Procedure currently requires the limit of liability for public and products liability insurance to be determined in accordance with Western Power's network access arrangement. Currently, the access arrangement requires a public liability insurance limit of not less than $50 million. After considering feedback from several independent insurance brokers, AEMO believes the limit of $50 million to be too low.
TC	The TC cost methodology prescribed in the Market Procedure is currently based on actual connection costs and access offers identified by Western Power. Limited new generation capacity is currently being built in the WEM, resulting in less project data available when calculating TC costs. The 2017 BRCP TC calculation contained no actual project data and resulted in an estimation 9.5% higher than the 2016 BRCP.

APPENDIX A. WACC

The pre-tax real WACC is applied in the determination of the BRCP. The formula is:

$$WACC_{real} = \left(\frac{1+WACC_{nominal}}{1+i}\right) - 1$$

where

$$WACC_{nominal} = \left(\frac{1}{1 - t(1 - \gamma)}\right) R_e \frac{E}{V} + R_d \frac{D}{V}$$

and the nominal return on equity is calculated as:

$$R_e = R_f + \beta_e \times MRP$$

while the nominal return on debt is calculated as:

$$R_d = R_f + (DRP + d)$$

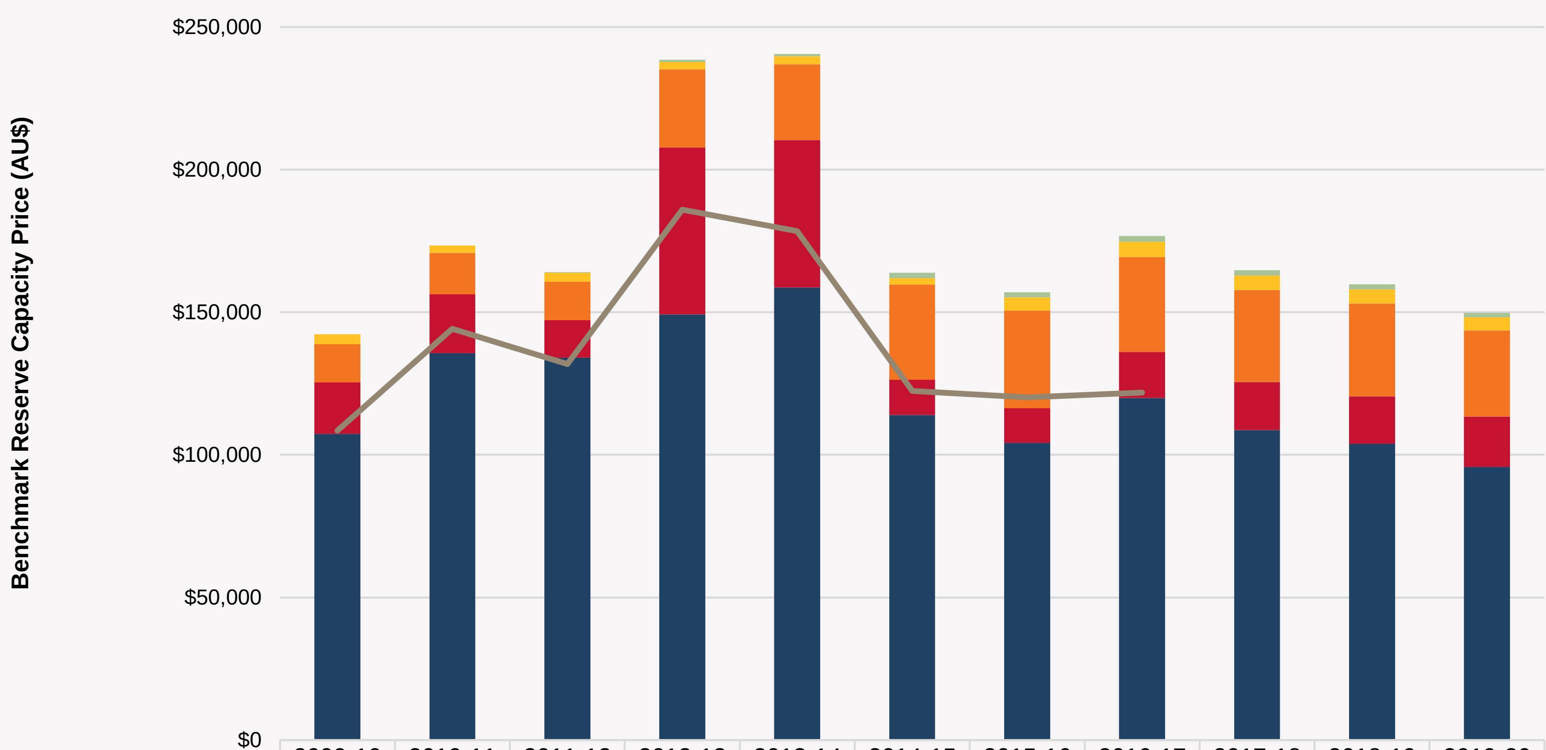
The WACC parameters applied in the 2016 BRCP and the proposed 2017 BRCP are shown in Table 9.

Table 9 WACC parameters for the 2016 and 2017 BRCP

Parameter	Notation	2016 value	2017 value
Nominal risk free rate of return (%)	R_f	2.92	2.57
Expected inflation (%)	i	2.45	2.39
Real risk free rate of return (%)	R_{fr}	0.46	0.18
Market risk premium (%)	MRP	6	6
Asset beta	β_a	0.5	0.5
Equity beta	β_e	0.83	0.83
Debt risk premium (%)	DRP	2.363	2.220
Debt issuance cost (%)	d	0.125	0.125
Corporate tax rate (%)	t	30	30
Franking credit value	γ	0.25	0.25
Debt to asset ratio (%)	D/V	40	40
Equity to total asset ratio (%)	E/V	60	60

APPENDIX B. HISTORICAL BRCP COMPONENT COST BREAKDOWN

Figure 2 Historical BRCP component cost breakdown



	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Land cost (LC)	$-	$-	$293	$769	$818	$1,973	$1,783	$2,064	$1,912	$1,831	$1,650
Fixed fuel cost (FFC)	$3,456	$2,631	$3,151	$2,615	$2,825	$2,239	$4,680	$5,442	$5,061	$4,886	$4,620
Fixed O&M cost	$13,363	$14,392	$13,431	$27,335	$26,649	$33,384	$34,239	$33,238	$32,307	$32,582	$30,143
Transmission cost (TC)	$18,017	$20,672	$13,151	$58,493	$51,621	$12,329	$12,164	$16,127	$16,860	$16,624	$17,691
Power station cost (PC)	$107,404	$135,701	$134,091	$149,306	$158,710	$113,971	$104,178	$119,942	$108,649	$103,898	$95,745
Reserve Capacity Price	$108,459	$144,235	$131,805	$186,001	$178,477	$122,428	$120,199	$121,889			

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
AU$	Australian dollar
MW	Megawatt

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
ANNUALISED_CAP_COST	Annualised capital cost
ANNUALISED_FIXED_O&M	Annualised fixed operating and maintenance cost
BRCP	Benchmark Reserve Capacity Price
CAP_COST	Capital cost
CC	Capacity Credit
CPI	Consumer price index. Used as a general price inflation index during escalations.
DRP	Debt risk premium
EMR	Electricity Market Review
ERA	Economic Regulation Authority
FFC	Fixed fuel costs
LC	Land cost
M	Margin to cover legal, approval, financing and other costs and contingencies
MRCP	Maximum Reserve Capacity Price
PC	Power station capital cost
PwC	PricewaterhouseCoopers Australia
RBA	Reserve Bank of Australia
OCGT	Open cycle gas turbine
O&M	Operating and maintenance
SWIS	South West interconnected system
TC	Transmission connection costs
TUOS	Transmission use of system
WA	Western Australia
WACC	Weighted average cost of capital
WEM	Wholesale Electricity Market