Procedure change proposal: Calculation of benchmark reserve capacity price
(EEPC_2020_02)

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Economic Regulation Authority
WESTERN AUSTRALIA

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Wednesday, 14 October 2020

The ERA invites comment on this paper and encourages all interested parties to provide comment on the matters discussed in this paper and any other issues or concerns.

As per clause 2.10.7 of the Wholesale Electricity Market Rules submissions should be made using the form available on the Market Website.

We would prefer to receive your submission form via email:

Email: publicsubmissions@erawa.com.au

You can also send the submission form through:

Post: PO Box 8469, PERTH BC WA 6849

Please note that submissions provided electronically do not need to be provided separately in hard copy.

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

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Executive summary

This procedure change proposal recommends amendments to the current market procedure for the calculation of the benchmark reserve capacity price (BRCP): one of the main factors in the calculation of the reserve capacity price in the Wholesale Electricity Market. Interested stakeholders are invited to provide feedback to the ERA on the proposed changes to the market procedure.

Under the Wholesale Electricity Market rules the ERA is responsible for reviewing the market procedure for the calculation of the BRCP at least once every five years.[1] The market rules require the ERA to ensure that any amendments are consistent with the Wholesale Market Objectives, the market rules, the *Electricity Industry Act 2004* and the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*.[2]

The reserve capacity mechanism in the Wholesale Electricity Market (WEM) seeks to maintain the adequacy of capacity in the South West Interconnected System to reliably meet demand. The mechanism achieves this aim by procuring capacity at the lowest cost possible. This seeks to minimise the long-term supply cost of electricity to consumers while maintaining the reliability of the system.

The Australian Energy Market Operator (AEMO) annually assesses the contribution of resources to meeting peak demand in the system and assigns capacity credits consistent with their expected contribution. Each retailer procures capacity credits from suppliers consistent with the retailer's contribution to peak demand. AEMO calculates the price of capacity credits based on the BRCP and the amount of excess capacity credits: that is, the capacity credits offered beyond that required to meet the adequacy target of the system. The larger the amount of excess capacity credits, the lower the price of capacity credits. This is to reflect the value of additional capacity to consumers from an improved level of reliability.

AEMO calculates the BRCP as the annualised fixed costs of a 160 MW liquid-fuelled open cycle gas turbine per amount of capacity credits expected to be assigned to the facility. Through the consultation process for the annual calculation of the BRCP, stakeholders have raised concerns that the reference facility is no longer an appropriate choice for investment in the WEM, the parameters and method for the calculation of the cost of capital are outdated and some investment or operating costs are inaccurate or missing.[3]

The market rules also require the ERA to review the method used to calculate the BRCP, as well as the market procedure. The ERA commenced these two reviews together in November 2019. However, as the ERA commenced the reviews, it identified considerable overlap with the current reforms being developed by the Energy Policy WA.

The ERA postponed the review of the method for setting the BRCP and to continue with the review of the market procedure.[4] After consultation with the Market Advisory Committee Working Group established for the review of the market procedure, the ERA limited the scope of the review to the calculation of the cost of capital in the market procedure. Limiting the scope allows the ERA to fast-track the amendment process, with the aim to publish a revised market procedure in time for AEMO to apply to the calculation of the BRCP this year.

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1 Clause 1.17.5(e) of the market rules allows the ERA to conduct the next review of the market procedure any time after 31 October 2017.

2 Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 2.10, (online).

3 AEMO, 2019, 2020 benchmark reserve capacity price for the 2022-23 capacity year, p. 20, (online).

4 ERA, 2020, *Notice: Review of the methods used to calculate the benchmark reserve capacity price and energy price limits, Suspension of the method reviews*, (online).

The ERA expects to complete its review of the market procedure in early November 2020, which would enable AEMO to update its estimate of the BRCP this year based on the updated market procedure.

This procedure change proposal contains the ERA's reasoning for amendments to the calculation of the weighted average cost of capital in the market procedure. This includes moving from a real to a nominal WACC. The use of a nominal WACC ensures that efficient generator financing cost includes compensation for forecast inflation. This change will set the necessary foundations for any future consideration of the annualisation process for capital as part of a broader review of the BRCP. Future consideration of the annualisation process would need to consider how investors project forward BRCP cashflows given uncertainties with future generation costs and efficiencies.

The procedure change proposal also provides a marked-up copy of the market procedure indicating the proposed changes in Appendix 1. Overall, the proposed changes would raise the value of the weighted average cost of capital, and hence the value of the BRCP. An illustrative example shows that AEMO's recently estimated weighted average cost of capital would increase from 3.51 per cent to 5.47 per cent using the proposed changes in the calculation.[5]

This paper also provides a summary of the feedback from the Working Group of the Market Advisory Committee for the review of the market procedure.

[5] For the 2020 reserve capacity cycle BRCP, AEMO applied a weighted average cost of capital of 3.51 per cent per annum (in real terms). Refer to AEMO, 2019, *Final report: 2020 benchmark reserve capacity price for the 2022-23 capacity year*, (online).

1. Introduction

The design of the WEM includes a reserve capacity mechanism to ensure that enough supply capacity is available to reliably satisfy demand, including during some defined supply emergencies. AEMO uses the reliability planning criterion outlined in the Wholesale Electricity Market Rules to establish the level of capacity required to maintain system adequacy: this is referred to as the reserve capacity target.[6]

Two years in advance, AEMO measures the expected contribution of facilities to meeting the reserve capacity target and assigns capacity credits to suppliers according to their expected contribution. Capacity suppliers receive payments consistent with the number of capacity credits they hold and in return commit to providing their capacity to AEMO in the delivery year.[7] The capacity payments provide incentives for investment when the system requires new capacity.

The cost of capacity payments should be balanced against the benefits of procuring capacity to improve the reliability of the system. Retailers fund the procurement of capacity and ultimately pass their cost to consumers through retail electricity tariffs. Although consumers value a secure and reliable electricity supply, they should not be expected to pay for excess capacity that provides little additional benefit to system security and reliability.

The market rules specify a method for determining the price of each megawatt of capacity credit provided to suppliers.[8] The BRCP is an input to this price determination. The calculation of the BRCP, together with its application in the determination of capacity price, seeks to balance the cost to consumers of procuring capacity credits against the benefits to consumers of improving the reliability of electricity supply.[9] In this way, the calculation of the BRCP is consistent with the objectives of the WEM. These objectives include minimising long-term cost of electricity supply to consumers, promoting the reliable supply of electricity, and avoiding discrimination against energy technologies.[10]

AEMO uses a calculation method specified in a market procedure to estimate the BRCP. The ERA is responsible for reviewing this market procedure at least once every five years. This paper proposes the ERA's amendments to the current market procedure for the calculation of the BRCP, following that review.

This paper is organised as follows:

- The rest of section 1 summarises the current market procedure, explains the ERA's role, and outlines the requirements of the procedure change process under the market rules.
- Section 2 explains the scope of the review of the market procedure, stakeholders' feedback, and the ERA's plan for the next review of the market procedure.
- Section 3 explains the ERA's reasoning for the proposed amendments to the market procedure.
- Section 4 provides an illustrative example of the effect of proposed changes on the weighted average cost of capital.

6 Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 4.5.9, (online).

7 The market rules refer to the capacity delivery year as capacity year. A capacity year commences on 1 October each year.

8 Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 4.16, (online).

9 Public Utilities Office, 2019, *Improving Reserve Capacity pricing signals – a recommended capacity pricing model, Final recommendations report*, p. 23, (online).

10 Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 1.2.1, (online).

- Appendix 1 provides a marked up copy of the market procedure indicating the changes proposed to the market procedure.

The changes proposed would result in a better estimate of cost of capital for developing the reference power station costs in the WEM as specified in the market procedure. The estimate would be more likely to reflect the actual cost of capital of an investor. This provides for a better estimate of the BRCP and would help the reserve capacity mechanism to better achieve its purpose of maintaining the reliability of the system at the lowest cost possible. These proposed changes help the WEM to better achieve its objective of maintaining the reliability of the system and minimising the long-term supply cost of electricity to consumers.

1.1 Market procedure for the calculation of the benchmark reserve capacity price

AEMO uses a market procedure to calculate the BRCP, which estimates the BRCP as the annualised fixed costs per megawatt of assigned capacity credits to a liquid-fuelled open cycle gas turbine power station with a nameplate capacity of 160 MW. The costs included in the calculation of the BRCP cover capital expenditure, a return on the capital expenditure, and fixed operating and maintenance costs.

The calculation of the BRCP, as set out in the current market procedure, can be summarised as:

1. Consider a 160 MW open cycle gas turbine, which uses distillate as liquid fuel.
2. Calculate the number of capacity credits expected to be assigned to the plant.
3. Calculate the sum of the costs below as of the capacity delivery year:
    a. Capital expenditure (inclusive of the cost of capital during the construction period).
    b. Present value of fixed operating and maintenance costs during the economic life of the plant.
4. Calculate a weighted average cost of capital, assuming the project receives capacity credits through the reserve capacity auction.
5. Calculate an annuity payment using the total cost estimated in step 3 (as the present value of the annuity), weighted average cost of capital in step 4 (as discount rate) and a duration of 15 years.
6. The BRCP is the annuity calculated in step 5 divided by the number of capacity credits calculated in step 2.

Explanation

The main cost components of the BRCP for the 2022/23 capacity year were as follows:

- Total capital cost of $194 million, inclusive of funding costs incurred during the construction period.
- Total fixed operating and maintenance cost of $54.6 million.[11]

Using an estimated real weighted average cost of capital of 3.51 per cent per annum and an annuity period of 15 years, the total annualised cost of developing and operating the power plant was approximately $21.6 million.

The annualised cost divided by the number of capacity credits expected to be assigned to the reference power station (approximately 152 MW) yielded a BRCP of approximately $142,000 per MW per year.[12]

1.2 The ERA's responsibility for reviewing the market procedure

The market rules require the ERA to review the market procedure for the calculation of the BRCP at least once every five years.[13,14] The ERA must undertake a public consultation process on the outcome of the review.

If the ERA recommends changes as a result of the review, the ERA must submit a rule change proposal to the Rule Change Panel or initiate a procedure change process to implement those changes.[15]

The market rules also allow the ERA to conduct the next review of the market procedure, including any public consultation process on the outcomes of the review of the market procedure, after 31 October 2017.[16] The Independent Market Operator last reviewed the market procedure in 2013.

1.2.1 The procedure change process

If the ERA chooses to initiate a procedure change proposal, it must follow the procedure change process stipulated in the market rules.[17] The ERA must follow the Rule Change Panel's Procedure Administration market procedure when developing a procedure change proposal.

11 This represents the present value of fixed operating and maintenance costs of the facility over its assumed economic life.

12 ERA, 2020, Decision on the benchmark reserve capacity price to apply in the 2022/23 capacity year, (online)

13 Wholesale Electricity Market Rules (WA), 7 August 2020, Clauses 4.16.3 and 4.16.9, (online).

14 The Independent Market Operator, 2013, *Market procedure: maximum reserve capacity price, version 6*, (online).

15 Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 4.16.10, (online).

16 Ibid, Clause 1.17.5(e).

17 Ibid, Clause 2.10.

Any amendment to the market procedure must be consistent with the Wholesale Market Objectives, the market rules, the *Electricity Industry Act 2004* and the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*.[18]

After developing amendments to the BRCP market procedure, the ERA must publish a proposal and call for submissions from the public.[19] This paper satisfies this requirement of the procedure change process.

1.2.1.1 Next steps

Following the receipt of submissions, the ERA will prepare a procedure change report.[20] The procedure change report will contain all the information outlined below:[21]

> 2.10.13. The Procedure Change Report must contain:
>
> (a) the wording of the proposed Market Procedure or amendment to or replacement for the Market Procedure;
>
> (b) the reason for the proposed Market Procedure or amendment to or replacement for the Market Procedure;
>
> (c) all submissions received before the due date for submissions, a summary of those submissions, and the response of the Rule Change Panel, AEMO, System Management or the Economic Regulation Authority, as applicable, to the issues raised in those submissions;
>
> (d) a summary of the views expressed by the Market Advisory Committee and, if the Market Advisory Committee has delegated its role to consider the Procedure Change Proposal to a Working Group under clause 2.3.17(a), a summary of the views expressed by that Working Group;
>
> (e) [Blank]
>
> (f) in the case of a Procedure Change Proposal developed by the Rule Change Panel, a proposed date and time for the Market Procedure or amendment or replacement to commence, which must, in the Rule Change Panel's opinion, allow sufficient time after the date of publication of the Procedure Change Report for Rule Participants to implement changes required by it;
>
> (g) in the case of a Procedure Change Proposal developed by AEMO (including in its capacity as System Management), a proposed date and time for the Market Procedure or amendment or replacement to commence, which must, in AEMO's opinion, allow sufficient time after the date of publication of the Procedure Change Report for Rule Participants to implement changes required by it;
>
> (h) in the case of a Procedure Change Proposal developed by the Economic Regulation Authority, a proposed date and time for the Market Procedure or amendment or replacement to commence, which must, in the Economic Regulation Authority's opinion, allow sufficient time after the date of publication of the Procedure Change Report for Rule Participants to implement changes required by it; and
>
> (i) in the case of a Procedure Change Proposal developed by a Network Operator, a proposed date and time for the Market Procedure or amendment or replacement to commence, which must, in the Network Operator's opinion, allow sufficient time after the date of publication of the Procedure Change Report for Rule Participants to implement changes required by it.

[18] Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 2.9.3, (online).

[19] This must allow for a 20 business days of consultation period.

[20] Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 2.10.10, (online).

[21] Ibid, Clause 2.10.13.

2. Scope of review

A complete review of the market procedure must address the three elements below:

- the facility that is a suitable choice for setting the BRCP
- the number of capacity credits expected to be assigned to the chosen facility
- the fixed investment and operating and maintenance costs of the reference facility.

The ERA intended to conduct a comprehensive review of the principles for setting the BRCP considering its role in capacity credit pricing, the governance process for the calculation of the BRCP and the calculation method in the market procedure.[22,23] The ERA commenced a review of the market procedure together with the review of the method for setting the BRCP in November 2019.

2.1.1 Decision to postpone the method review

Due to overlap between the review of the method for setting the BRCP and the State Government's energy reform process, the ERA decided to postpone the review of the method until after the completion of the reforms. In March 2020, the ERA published a notice and advised stakeholders of this decision.[24]

Energy Policy WA (EPWA) is currently developing changes to the market rules that account for the effect of network constraints in assigning capacity credits to facilities. EPWA is also developing a method for the assignment of capacity credits to storage facilities. The details of the changes are currently under development and it is not clear how they will affect capacity credits to facilities, including new facilities that intend to enter the market. EPWA has indicated the possibility of further changes to the reserve capacity mechanism. However, the scope of these possible changes is not yet clear.[25]

2.1.2 Decision to continue with limited review of market procedure

The ERA decided to continue with the review of the market procedure. Through AEMO's annual BRCP determination and consultation process, many stakeholders have raised concerns with the current method for calculating the BRCP.[26] The BRCP is a main determinant of the price of reserve capacity credits and small changes can materially influence cash flows for new and existing market participants. In February 2020, the Minister for Energy implemented a new capacity pricing mechanism, for which the BRCP is a main input. The

22 Ibid, Clause 2.26.3, (online).

23 In its previous review of the methodology in 2013, the ERA considered that the scope of the review of the methodology covers the high-level concepts and principles for setting the BRCP, including the governance of the process. The ERA's review of the market procedure ensures those principles carry through consistently in the implementation of the method for the calculation of the BRCP. ERA, 2013, *Review of methodology for setting the maximum reserve capacity price and the energy price limits in the Wholesale Electricity Market*, p. 43, (online).

24 ERA, 2020, *Notice: Review of the methods used to calculate the benchmark reserve capacity price and energy price limits, Suspension of the method reviews*, (online).

25 EPWA, Webpage: *Improving reserve capacity pricing signals*, accessed: 26 March 2020, (online).

26 AEMO, 2019, *Final report: 2020 benchmark reserve capacity price for the 2022-23 capacity year*, p. 19–20, (online).

ERA determined that a review of the method for setting the BRCP was needed to ensure this new capacity pricing mechanism also used the best estimate of the BRCP.

Due to the overlaps outlined above, the ERA decided to limit the review of the market procedure to the method used to estimate the weighted average cost of capital. This is in response to stakeholders' concerns. As explained in section 2.2, stakeholders were keen for the ERA to complete this review in time for AEMO's calculation of the BRCP for the 2021 reserve capacity cycle.

The ERA proposes to postpone the assessment of other parts of the market procedure, including the choice of reference facility, until after the reforms are complete and there is more clarity on the expected constraints on the network and the amount of network access quantity available to new entrants.

2.2 Stakeholder feedback

The procedure change process stipulated under the market rules allows the ERA to seek the advice of the Market Advisory Committee (MAC) when conducting the review.[27] The MAC can also consider providing feedback to the ERA through meetings or by delegating its role to a working group of rule participants and other stakeholders.[28]

On 16 June 2020, the ERA presented a high-level scope of the review and asked the MAC whether it considered a working group was required to provide feedback to the ERA for the review of the market procedure. The MAC considered that a working group should be convened.[29] The Rule Change Panel developed the terms of reference for the Working Group, including the ERA's proposed scope and high-level timeline for the review.[30] The ERA intended to review the calculation of the weighted average cost of capital and fixed operating and maintenance costs and expected to complete the review in February 2021.

A market participant raised concern about the ERA's proposed review timeline, explaining that given the proposed completion of the review in 2021, AEMO's calculation of the BRCP for the 2021 reserve capacity cycle would continue to be based on the current version of the market procedure, which used outdated parameters for the calculation of the weighted average cost of capital. The market participant asked whether the proposed timeline could be shortened to enable AEMO to use a revised market procedure for the 2021 reserve capacity cycle.

The ERA engaged with AEMO to explore if AEMO's timeline for the calculation of the BRCP this year could allow for the application of a new market procedure in the calculation. AEMO started its process for determination of the BRCP for the 2021 reserve capacity cycle in July 2020.

In the first meeting of the Working Group on 18 August 2020, the ERA sought advice on its proposed fast-track process. Before the meeting, the ERA provided the Working Group with a draft procedure change proposal based on reviewing the calculation of the weighted average cost of capital only and sought feedback.

27 Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 2.10.9, (online).

28 Ibid, Clause 2.3.17.

29 Rule Change Panel, 2020, Meeting minutes: Market Advisory Committee meeting 16 June 2020, pp. 19–20, (online).

30 Rule Change Panel, 2020, Terms of reference: benchmark reserve capacity price Working Group, (online).

The Working Group supported the ERA's fast-track review this year and limiting the scope of the review to the calculation of weighted average cost of capital only.[31] Alinta Energy, the Australian Energy Council, Perth Energy and Synergy provided feedback on the draft procedure change report and supported the fast-track process for the review of the market procedure in their submissions.[32]

The working group members are not a representative cross section of all interested parties. Most representatives on the working group have generation businesses and the ERA recognises their interest in supporting changes that increase the cost of capital and value of the BRCP. All three responses from working group members considered that the current calculation of the weighted average cost of capital underestimated the cost of capital. They considered this was because the calculation underestimated the risk that private investors faced when developing power generation projects in the WEM. These submissions indicated increasing investment risk for electricity generation projects due to changes and uncertainties in the market, including changes to the reserve capacity pricing mechanism, changing demand levels, the removal of long-term special capacity credit price arrangements for new entrants, and deep transmission connection costs from the calculation of the BRCP. Working group member comments about the calculation of weighted average cost of capital are addressed in section 3.

2.3 The next review of the market procedure

The ERA considers that, ideally, a comprehensive review of calculating the BRCP would be conducted concurrently with the review of the method for setting the BRCP and the pricing curve for capacity credits. This is because the calculation of the BRCP and the design of the capacity credit pricing curve interact. Reviewing all three elements at once would ensure that that the pricing of capacity credits is consistent with the objectives of the reserve capacity mechanism. Under the market rules the ERA is responsible for reviewing:

- the capacity credit pricing curve (clause 2.26.3A).
- the method for setting the BRCP (clause 2.26.3).
- the market procedure for calculating the BRCP (clause 4.16.9).

The ERA's review of the capacity credit pricing curve commences after 30 September 2022.[33] The ERA intends to conduct a comprehensive review of the capacity credit pricing curve, the method for setting the BRCP and the market procedure for calculating the BRCP in 2022, after the completion of the State Government's reform program.

[31] Rule Change Panel, Webpage: Benchmark reserve capacity price Working Group (online).

[32] Submissions are available on the Working Group's website (online).

[33] Wholesale Electricity Market Rules (WA), 7 August 2020, Clause 1.13.1, (online).

3. Cost of capital in the market procedure

Section 2.9 of the market procedure calculates a weighted average cost of capital (WACC):

- To estimate initial financing costs, which are added in to the reference power station's capital expenditures. This accounts for project financing costs before the commissioning of the power station and the realisation of revenues from participation in the WEM.
- To convert the power station's capital costs into an annualised cost that can be recovered over the assumed life of the power station. In this annuity approach, the WACC represents a long-term required rate of return over the life of the asset.

Each year, the market procedure requires AEMO to estimate the WACC. AEMO's annual review involves two sets of components listed in sections 2.9.3 and 2.9.8 of the market procedure, these are:

- Annual components, which require review each year and comprise the risk free rate, expected inflation, debt risk premium and corporate tax rate.
- Structural components, which are fixed in the procedure and remain constant between the five-yearly reviews of the BRCP by the ERA. As part of the annual review, AEMO may review and determine values for structural components that differ from those specified in the procedure if it considers that a significant economic event has influenced those components. These structural components include the market risk premium, equity beta, debt issuance costs, franking credit value and gearing ratio.

3.1 The ERA's approach to determining the WACC

The ERA reviewed and updated its approach to the calculation of the WACC for electricity networks, gas pipelines and rail in 2018 and 2019. These reviews have informed the ERA's review of the WACC for the calculation of the BRCP.

On 20 September 2018, the ERA published its final decision on Western Power's access arrangement for 2017 to 2021. This final decision detailed the ERA's approach to determining rate of return for Western Power's access arrangement.[34]

On 18 December 2018, the ERA published its final gas rate of return guidelines.[35] These guidelines specify the ERA's approach to determining the rate of return for the gas pipelines it regulates. This approach is then used to set the rate of return to apply over a gas pipeline's access arrangement.

On 22 August 2019, the ERA published its final determination for the WACC to be used in the regulation of access to railways in Western Australia for the 2018 and 2019 periods.[36] Under the *Railways (Access) Code 2000*, the ERA is required to determine each year a WACC to be applied in the establishment of capital costs for regulated railways. Every five years the ERA is required to consider its approach to determining the rail WACC. The ERA's 2019 final determination reflects the outcomes from its latest review of the rail WACC.

[34] ERA, 2019, *Final Decision on Proposed Revisions to the access Arrangement for the Western Power Network 2017/18 – 2021/21*, September 2018.

[35] ERA, 2018, *Final Gas Rate of Return Guidelines Explanatory Statement*, December 2018.

[36] ERA, 2019, *Final Determination 2018 and 2019 Weighted Average Cost of Capital for the Freight and Urban Networks and Pilbara Railways*, August 2019.

The purpose of the WACC in the rail framework is similar to the purpose of the WACC used for the BRCP because the WACC:

- Represents a long-term required rate of return.
- Is used in an annuity calculation to calculate an annual compensation to the investor for capital costs over the life of the asset.
- Is updated annually to reflect efficient financing costs at a point in time.

3.2 Calculation of the WACC in the market procedure

Section 2.9 of the market procedure provides AEMO with direction on how the WACC is to be calculated. Specifically, sections 2.9.6 and 2.9.7 detail the high-level framework to be used:

> 2.9.6 The IMO shall compute the WACC on the following basis:
>
> (a) The WACC shall use the Capital Asset Pricing Model (CAPM) as the basis for calculating the return to equity.
>
> (b) The WACC shall be computed on a Pre-Tax basis.
>
> (c) The WACC shall use the standard Officer WACC method as the basis of calculation.
>
> 2.9.7 The pre-tax real Officer WACC shall be calculated using the following formulae:

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

and

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

where,

$WACC_{real}$	is real WACC
$WACC_{nominal}$	is nominal WACC
i	is forecast inflation
t	is corporate tax rate
γ	is the value of franking credits
R_e	is nominal return on equity
R_d	is nominal return on debt
$\frac{E}{V}$	is market value of equity as a proportion of the market value of total assets
$\frac{D}{V}$	is market value of debt as a proportion of the market value of total assets

3.2.1 The ERA's approach

The ERA's overall rate of return approach across energy and rail sectors is largely consistent with that detailed in the market procedure for the calculation of the BRCP.

The ERA's gas rate of return instrument requires that the ERA adopts a "nominal vanilla" WACC to develop the rate of return for the benchmark efficient entity. A vanilla WACC does not include any adjustment for tax effects, such as the effect of imputation credits on the rate of return. The effect of tax on returns must be accounted for separately, as an explicit deduction from the relevant cash flow. A vanilla WACC is therefore a post-tax framework.

The requirements for the WACC for BRCP are similar to those for the ERA's rail WACC:

- The *Railways (Access) Code 2000* requires the estimation of annual capital costs through an annuity that provides for the return on and of the cost of building a new railway.
- For rail the ERA calculates a pre-tax WACC. The pre-tax approach is preferred as the estimation of future tax liabilities may not be consistent with the light-handed nature of the *Railways (Access) Code 2000* and the determination of the asset base on a gross replacement valuation basis. The development of tax accounts is also complex.

For the calculation of the BRCP the ERA continues to support a WACC calculated:

- on a pre-tax basis
- through the standard Officer WACC method.

3.2.2 Nominal or real WACC

3.2.2.1 Stakeholder comments

In its 2020 BRCP report, AEMO noted that a negative real risk free rate, and subsequently a low WACC, did not reflect Australian market conditions at that point in time.[37] AEMO also noted that market participants queried the WACC method and provided this information to the ERA for consideration in the five-yearly review of the market procedure.[38, 39]

Alinta Energy acknowledged that the overstated inflation rate used in the most recent determination contributed to the understated WACC. Alinta supported the ERA's further analysis of options to rectify this issue, including using a nominal WACC or reforming the method to forecast inflation.[40] The Australian Energy Council also noted that a review of the inflation component would be especially useful.[41]

[37] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, pp. 12, 14.

[38] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, p. 14.

[39] Alinta Energy, *Submission to AEMO Draft Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year,* October 2019.

[40] Alinta Energy, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

[41] Australian Energy Council, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

3.2.2.2 The ERA's approach

At present, the market procedure details how to calculate a nominal and real WACC. The market procedure does not, however, detail whether a nominal or real WACC should be applied in the annuity process to calculate the annualised capital cost. AEMO has applied a real WACC.

It is important for the WACC to set an efficient benchmark for the financing of a new generator at a point in time. Efficient financing costs include compensation for the time value of money. A prudent and efficient new generator investor would issue nominal debt and would be contractually required to make nominal interest payments (this includes a component for expected inflation). Similarly, an efficient equity investor would seek to be compensated for expected inflation.

Investors can be compensated for inflation:

- through a nominal WACC, which includes a component for inflation;

  or

- through a real WACC plus an additional adjustment mechanism.

Electricity and gas networks target the delivery of a real WACC through specific adjustment mechanisms that:

1. Initially uses a nominal WACC in revenue modelling.
2. Undertakes annual adjustments to:
   a. Remove expected inflation from the post-tax revenue model.
   b. Escalate historic capital expenditure by actual inflation.

The BRCP procedure provides the best annual estimate of generator capital costs at a point in time and has no adjustment mechanism to compensate investors for inflation.

- There is no recognition of historic capital expenditure and historic capital investment is not carried through time.
- There is no adjustment for past inflation expectations nor adjustment for actual inflation.

Therefore, the BRCP's use of a real WACC makes no allowance for inflation and does not match the efficient financing costs that a benchmark new generator would incur when financing a new plant.

The ERA supports the use of a nominal WACC to:

- Provide investors with compensation for expected inflation.
- Meet the Net Present Value = 0 principle.[42]
- Provide efficient price signals to market.

The adoption of a nominal WACC also addresses stakeholders' and AEMO's concern that current negative real risk free rates and low real WACCs do not reflect Australian market

[42] The Net Present Value = 0 principle is a regulatory principle that ensures the present value of future cash flows is equal to the initial investment. That is, investors receive cashflows sufficient to recover their initial investment, no more and no less.

conditions. The market procedure's inflation forecast delivers a relatively static inflation forecast of around 2.3 per cent.[43] This higher rate compares to inflation expectations of around 1 per cent being built into market bond yields and the Reserve Bank of Australia's expectation that inflation will average between 1 and 1.5 per cent over the next few years. [44] The market procedure's inflation forecast is inconsistent with market expectations built into other WACC parameters.

Moving to a nominal WACC approach removes the need to forecast inflation, as market expectations are already built into a nominal WACC.

The use of a nominal WACC will also set the necessary foundations for any future consideration of the annualisation process as part of a broader review of BRCP.

- The use of a nominal WACC ensures that the annualised capital cost includes compensation for inflation.
- Any future reform to the annualisation will then be considered from this baseline level.
- For example, the annualisation process could provide an allowance for reductions in forecast new generator capital costs to recognise risk to capital recovery. This adjustment to the annualisation process could occur through bringing forward the recovery of capital. In this case, more capital would be recovered in the early years of the 15-year generator life. This would result in a higher first year annual capital cost, compared to a straight annuity with a nominal WACC (which has the same annual payment for each year of the 15-year term).

Amendment 1: The annualisation process to use nominal WACC

The ERA proposes to amend sections 2.9.7 and 2.10.1 to clarify that a nominal WACC should be used to calculate annualised capital costs.

3.3 Return on equity

The return on equity is the return that investors require from a firm to compensate them for the risk they take by offering their capital. There are no readily observable proxies for the expected return on equity. While estimates of the cost of debt can be obtained by observing debt instruments, financial markets do not provide a directly observable proxy for the cost of equity, for either individual firms or for the market.

To date, Australian regulators have used the Sharpe-Linter Capital Asset Pricing Model (CAPM) to quantify the return on equity:

$$R_i = R_f + \beta_i(R_m - R_f)$$

where,

[43] The current market procedure's approach to forecasting inflation uses: 1) the Reserve Bank of Australia's annual estimates of inflation over the next two years; and 2) the mid-point of the Reserve Bank of Australia's 2 per cent to 3 per cent inflation target range (2.5 per cent) for the remaining eight years of the forecast period. The large weight placed on the mid-point of the inflation target leads to a relatively static forecast of inflation of around 2.3 per cent.

[44] RBA, *Statement by Philip Lowe, Governor: Monetary Policy Decision*, 4 August 2020 (online)

R_i is the required rate of return on equity for the asset, firm or industry in question

R_f is the risk free rate

β_i is the equity beta that describes how the return for a particular asset will follow the market return, which is defined as,

$$\beta_i = cov(R_i, R_m)/\sigma_{R_m}^2$$

$R_m - R_f$ is the market risk premium.

The market procedure 2.9.6(a) and 2.9.7(a) require AEMO to determine the nominal return on equity by using the CAPM.

3.3.1 The ERA's approach

The ERA uses the CAPM to determine a single point estimate for the return on equity. The CAPM estimates the required return on the equity share of an asset as a linear function of the risk free rate and a component reflecting the market risk premium that investors would require over the risk free rate.

For the BRCP, the ERA continues to support the use of the CAPM.

3.4 Risk free rate

The risk free rate is the return an investor would expect when investing in an asset with no risk. This is the rate of return an investor receives from holding an asset with a guaranteed payment stream. Since there is no likelihood of default, the return on risk free assets compensates investors for the time value of money.

The risk free rate of return can be estimated as either nominal or real. The nominal risk free rate includes compensation to investors for the reduction in purchasing power caused by inflation. The real risk free rate of return would prevail if the expected inflation rate was zero during an investment period.

The market procedure specifies how the nominal risk free rate should be determined.

> 2.9.7 (g) The nominal risk free rate, for a Capacity Year is the rate determined for that Capacity Year by the IMO on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years:
>
> • using the indicative mid rates published by the Reserve Bank of Australia; and
>
> • averaged over a 20-trading day period;
>
> 2.9.7 (i) If there are no Commonwealth Government bonds with a maturity of 10 years on any day in the period referred to in step 2.9.7(g), the IMO must determine the nominal risk free rate by interpolating on a straight line basis from the two bonds closest to the 10 year term and which also straddle the 10 year expiry date.
>
> 2.9.7 (j) If the methods used in step 2.9.7(i) cannot be applied due to suitable bond terms being unavailable, the IMO may determine the nominal risk free rate by means of an appropriate approximation.

The market procedure does not treat the risk free rate for debt and equity differently. Section 2.9.8 states that the risk free rate is reviewed annually.

3.4.1 The ERA's approach

The ERA uses observed yields from Commonwealth Government bonds as the best proxy for risk free assets in Australia to estimate the risk free rate of return.

To calculate the risk free rate, the ERA uses indicative mid-rates published by the Reserve Bank of Australia. Where there are no Commonwealth Government bonds with a maturity of exactly 10 years the ERA interpolates the risk free rate on a straight line basis.

The use of a 10-year term for the risk free rate is consistent with that intended for the WACC for the purposes of BRCP calculations, which is to reflect a long-term rate of return for the annuitisation of capital costs over the life of the reference plant.

The use of a 10-year term is consistent with the ERA's approach to the rail WACC. For a return on equity and debt, a term of 10 years is used to estimate returns. Although terms longer than 10 years are available for the risk free rate, a risk free rate with a 10-year term allows components of models to be estimated consistently and provides for inclusion of reasonable number of bonds in the calculation.

The ERA notes stakeholder concerns with negative real risk free rates. However, the BRCP process uses a nominal risk free rate, which includes a component for the market's expectations of inflation. A real return is calculated at a WACC level.

The ERA continues to support:

- The existing approach to determine the risk free rate.
- The risk free rate being updated annually.

3.5 Market risk premium

The market risk premium is the expected rate of return over and above the risk free rate that investors require to invest in a fully-diversified portfolio. *Ex ante*, investors always require a rate of return above the risk free rate to invest and so the expected market risk premium is always positive.

The market risk premium compensates an investor for the systematic risk of investing in a fully diversified portfolio. Systematic risk is risk that cannot be eliminated by investing in a diversified portfolio of assets, because such risk affects all assets in the market.[45] Therefore, the market risk premium represents an investor's required return, over and above the risk free rate of return, on a fully diversified portfolio of assets. This is a forward-looking concept.

Section 2.9.8 of the market procedure sets a market risk premium of 6.0 per cent. The procedure requires a review of the parameter every five years. For the 2020 BRCP calculation, AEMO adopted a market risk premium of 6.0 per cent.[46]

[45] The foundation of the Sharpe-Lintner CAPM is the proposition that adding an asset to a portfolio reduces risk via the diversification effect but not beyond the risks that the assets in a portfolio share in common, that is, their systematic risk. At the limit, when one has invested in all available assets in the market portfolio, there is only systematic risk left. An important assumption of the CAPM is that assets are priced as though it is only their systematic risk that is relevant to investors.

[46] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, p.23.

3.5.1 Stakeholder comments

Synergy's submission to the BRCP market procedure change addressed the market risk premium. Synergy did not consider that a reduction of the market risk premium was reflective of the general market uncertainty observed in the South West Interconnected System (SWIS) and did not support a decrease.[47]

3.5.2 The ERA's approach

The market risk premium is a market parameter and is therefore unaffected by the industry or asset for which the return on equity is being calculated.

While estimates of the cost of debt can be obtained by observing debt instruments, the financial markets do not provide a directly observable proxy for the cost of equity for either individual firms or the market. The market risk premium cannot be directly observed because it depends on investor expectations at the time of investment. In order to set the return on equity, the market risk premium needs to be estimated for a future time period.

The ERA reviewed the market risk premium as part of its rail determination. For rail networks, the ERA's forward-looking market risk premium was estimated for a 10-year period, consistent with the long lives of rail networks and the regulatory framework. The same approach is appropriate for the BRCP given it requires a long-term WACC.

For its rail WACC final determination, the ERA adopted a market risk premium of 5.9 per cent.[48]

The ERA supports:

- updating the market risk premium to be 5.9 per cent
- fixing the market risk premium until the next BRCP review.

Amendment 2: Update of market risk premium

The ERA proposes to update the market risk premium to 5.9 per cent in section 2.9.8.

3.6 Equity beta

Equity beta is the "slope" parameter b_i in the Sharpe-Lintner CAPM. The slope parameter b_i correlates the return on the specific asset, in excess of the risk free rate of return, to the return on the market portfolio.

The risk of an asset is typically thought of as the variance in asset returns. This variance is a measure of the total risk of an asset. Total risk consists of systematic and non-systematic risk. Systematic risk is that part of total risk in a firm's returns that stems from the economy and markets more broadly. Systematic risk cannot be eliminated through diversification. Non-systematic risk is the risk stemming from unique attributes of the firm, which may be

47 Synergy, *ERA's review of the Market Procedure: Benchmark Reserve Capacity Price,* September 2020, p. 2, (online).

48 ERA, *Final Determination 2018 and 2019 Weighted Average Cost of Capital for the Freight and Urban Networks and Pilbara Railways*, August 2019, p. 53.

eliminated by an investor through diversification. For this reason, only systematic risk is compensated in the return on equity.

The equity beta is a parameter that measures the systematic risk of a security or a portfolio in comparison to the market portfolio.

Section 2.9.8 of the market procedure specifies an equity beta of 0.83. For the 2020 BRCP calculation, AEMO adopted an equity beta of 0.83.[49]

3.6.1 Stakeholder comments

Alinta, the Australian Energy Council, Perth Energy and Synergy provided submissions to the BRCP market procedure change that discussed the high and increasing risks facing new generation projects in the SWIS. These parties submitted that the generation market in the SWIS was, and would continue to be, more volatile than it was when the WACC parameters were initially set, including the equity beta.[50] [51] [52] [53]

Synergy noted that the equity beta value of 0.83 could possibly be left unchanged for 10 years if not updated under the current review. Synergy also commented that changes introduced through the Energy Transformation Strategy set for 1 October 2022, such as the introduction of constrained network access, warranted a more frequent review of the equity beta parameter. [54]

3.6.2 The ERA's approach

To determine an equity beta, the ERA first selects a benchmark sample of comparable listed companies and then uses empirical approaches to estimate equity beta.

In considering beta, the ERA has reviewed the beta approaches in other jurisdictions with capacity markets in North America. The ERA found that:

- The approach to estimate the cost of capital is to establish a WACC range from: 1) individual WACC's for each of the sample generation companies; and 2) publicly available comparator discount rates from mergers and sales. Based on that WACC range, regulatory judgement is then used to determine a final WACC.[55] [56]
- This approach uses individual company equity betas to calculate the individual WACC's for each of the sample companies. The approach does not estimate a benchmark equity beta.

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49 AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, p.23.

50 Alinta Energy, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

51 Australian Energy Council, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

52 Perth Energy, *Benchmark Reserve Capacity Price,* August 2020 (online).

53 Synergy, *ERA's review of the Market Procedure: Benchmark Reserve Capacity Price,* September 2020 (online).

54 Synergy, *ERA's review of the Market Procedure: Benchmark Reserve Capacity Price,* September 2020, p. 2, (online).

55 The Brattle Group, *PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date,* 19 April 2018, pp. 35-46 (online).

56 The Brattle Group, *AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date*, 4 September 2018, pp. 30-33 (online).

- WACC was considered at a point in time and did not consider how a benchmark equity beta changed over time for any increased generator uncertainty. Pennsylvania New Jersey Maryland (PJM) Interconnection analysis did find that a reduction in recommended WACC over 2011 to 2018 was traced primarily to the fall in the long-term risk free rate.[57]
- The range of generator equity betas did vary depending on the sample companies chosen. PJM Interconnection analysis produced an equity beta range of 0.84 to 1.47 as of November 2017.[58] Alberta Electric System Operator analysis produced an equity beta range of 0.80 to 1.29 as of June 2018.[59] Independent System Operator New England analysis produced an equity beta range of 0.71 to 1.38 as of June 2020.[60] The ERA also analysed if there was an identifiable trend in these equity beta studies. However, detailed analysis of equity beta ranges and individual company equity betas did not produce a clear indication of trend.

The market procedure takes a different approach that involves determining a benchmark equity beta to inform the calculation of the benchmark WACC. This approach to beta is consistent with the general framework in Europe.[61] However, there is limited information on equity betas for individual European countries given a new framework is being considered.

In reviewing the equity beta, the ERA has considered data for the available benchmark sample of Australian listed generators. Australian generators are used as they relate directly to the Australian market. Betas from other countries need to be used cautiously because of differences in systematic risk between countries and difficulties in converting these estimates into Australian betas.[62]

There are two listed Australian generators available, AGL Energy and Infigen Energy. A third generator, Energy Developments Ltd, was available in the past. However, it has now been delisted. The ERA's beta analysis is presented in Table 1.

57 The Brattle Group, *PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date,* 19 April 2018, p. 37 (online).

58 The Brattle Group, *PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date,* 19 April 2018, p. 40 (online).

59 The Brattle Group, *AESO Cost of New Entry Analysis: Combustion Turbines and Combined-Cycle Plants with November 1, 2021 Online Date*, 4 September 2018, p. 36 (online).

60 Concentric Energy Advisors, *ISO-NE CONE and ORTP Analysis,* 12 August 2020, p. 7 (online).

61 European Network of Transmission System Operators for Electricity, *Proposal for a Methodology for calculating the Value of Lost Load, the Cost of New Entry for generation, or demand response, and the Reliability Standard in accordance with Article 23 of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast), 5 December 2019, p 15* (online).

62 Partington, G. and Satchell, S., *Report to the AER: Alternative Asset Pricing Models,* 30 June 2020, pp. 6-7.

Table 1: ERA beta analysis as at June 2020*

	Asset beta 5 year	Asset beta 10 year	Equity beta 5 year	Equity beta 10 year
AGL Energy	0.49	0.49	0.82	0.82
Infigen Energy	0.47	0.51	0.78	0.85

**Source: Bloomberg and ERA analysis. Initial raw equity betas are provided by Bloomberg based on the ASX 200 and daily data.*
Raw equity betas are de-levered by company gearing to estimate asset betas. Asset beta (also known as unlevered beta) is a measure that compares the risk of an unlevered company to the risk of the market. The unlevered beta is the beta of a company without any debt.
Asset betas are then re-levered by the benchmark 40 per cent gearing to calculate an equity beta based on the benchmark financial structure.

The analysis has produced an equity beta range of 0.78 to 0.85, which indicates that a 0.83 is still reflective of market data.

The ERA notes stakeholder comments that discussed the high and increasing risks facing new generation projects in the SWIS. Alinta and the Australian Energy Council considered that generators are facing higher risk as a result of changes to the reserve capacity price, continuous reform to the reserve capacity demand curve, increasingly volatile demand levels, greater price fluctuations and removal of the 10-year special price arrangement for new entrants.[63] [64] Perth Energy considered that the reserve capacity market was perceived by new investors as carrying substantial risk that cannot be hedged and that the process for developing the reserve capacity price has changed on several occasions.[65] Perth Energy considered that the WACC needs to incorporate an appropriate margin to recognise this risk if the reserve capacity mechanism is to encourage adequate investment in generation.[66]

The ERA has found no evidence of how generation risk has increased in other markets.

Until the current electricity reforms are fully implemented, it is hard to understand the future risk profile of a new generator in the SWIS and perform comparative risk analysis between a new SWIS generator and the generators in the benchmark sample to understand if and how equity beta may have to be adjusted. However, the ERA notes that past and current SWIS market reforms may have changed the risk perception of a new entrant generator. The ERA welcomes any evidence in response to this draft procedure change on how participants expect the reforms to change the systematic risk of a generator relative to the market as a whole.

The current equity beta of 0.83 for the BRCP compares to the ERA's equity beta of 0.7 for electricity and gas networks. The higher equity beta for the BRCP reflects the greater level of risk that generators are exposed to. The ERA support retaining an equity beta of 0.83.

3.7 Return on debt

The return on debt is the return that debtholders require from a firm to compensate them for the risk they take in providing debt financing to the company.

63 Australian Energy Council, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

64 Alinta Energy, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

65 Perth Energy, *Benchmark Reserve Capacity Price,* August 2020 (online).

66 Perth Energy, *Benchmark Reserve Capacity Price,* August 2020 (online).

The market procedure details how the return on debt is to be calculated. Section 2.9.7(b) specifies the nominal return on debt, R_d, for the relevant capacity year is:

$$R_d = R_f + DM$$

where R_f is the nominal risk free rate for the capacity year and DM is the debt margin, which is calculated as the sum of the debt risk premium, DRP, and debt issuance cost, d.

3.7.1 The ERA's approach

For energy and rail WACC determinations the ERA estimated the return on debt based on a risk premium over and above the risk free rate, combined with an additional margin for administrative costs: [67, 68]

Return on debt = risk free rate + debt risk premium + administrative costs

For the BRCP, the ERA continues to support the current approach to the return on debt in the market procedure.

3.8 Debt risk premium

The debt risk premium is the return above the risk free rate that lenders require to compensate them for the risk of providing debt funding to a firm. The debt risk premium compensates holders of debt securities for the possibility of default by the issuer.

The debt risk premium is closely aligned with the risk of the business. When issuing debt in the form of bonds, a credit rating can be assigned that reflects the probability of default of the issuer, and therefore the risk present in the bond.

The market procedure details how the debt risk premium is to be calculated.

> 2.9.7(h) The debt risk premium, DRP, for a Capacity Year is a margin above the risk free rate reflecting the risk in provision of debt finance. This will be estimated by the IMO as the margin between the observed annualised yields of Australian corporate bonds which have a BBB (or equivalent) credit rating from Standard and Poors and the nominal risk free rate. The IMO must determine the methodology to estimate the DRP, which in the opinion of the IMO is consistent with current accepted Australian regulatory practice.

Section 2.9.8 of the market procedure provides for an annual update to the debt risk premium.

AEMO has used the ERA's bond yield approach to estimate the debt risk premium since the 2018 BRCP determination, as it considered the ERA's method to be representative of the current accepted Australian regulatory practice.[69]

[67] ERA, *Final Determination 2018 and 2019 Weighted Average Cost of Capital for the Freight and Urban Networks and Pilbara Railways*, August 2019, p. 20.

[68] ERA, *Final Gas Rate of Return Guidelines Explanatory Statement*, December 2018, p. 83.

[69] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, pp.13-14.

3.8.1 The ERA's approach

For energy and rail the ERA uses the "revised bond yield approach" to determine the debt risk premium at a point in time by taking the following steps: [70, 71]

- Determining the benchmark sample – identifying a sample of relevant corporate bonds that reflect the credit rating of the benchmark efficient entity.
- Converting the bond yields from the benchmark sample into Australian dollar equivalent yields.
- Calculating an average Australian dollar equivalent bond yield for each bond across the averaging period.
- Estimating yield curves on the bond data by applying various techniques including Gaussian Kernel, Nelson-Siegel and Nelson-Siegel-Svensson techniques.
- Estimating the 10-year cost of debt by averaging the three yield curves of 10-year cost of debt based on the techniques used in the previous step.
- Calculating the debt risk premium by subtracting the 10-year risk free rate (or base rate) from the 10-year cost of debt.

The ERA revises the return on debt each year to incorporate an annual update of the estimate of the debt risk premium. Each year, the ERA calculates the latest value of the debt risk premium over the specified averaging period.

As part of its 2018 review of the gas rate of return guidelines, the ERA refined and developed publicly available tools for its debt risk premium method. This refinement has meant that the debt risk premium process is more robust and easier to implement. The tools and process documents are available on the ERA's website.[72] These set out the operating procedure for updating the debt risk premium estimates.

For energy, the ERA uses the annual estimate of the debt risk premium to calculate a 10-year trailing average for the debt risk premium. As the ERA estimates a new year's debt risk premium, the oldest estimate in the 10-year series is removed. This approach recognises that an efficient financing strategy for existing assets is to refinance 10 per cent of the debt portfolio every year.

For rail, however, the ERA uses the estimate of the on-the-day debt risk premium to reflect the debt premium at a forward-looking point in time. This approach seeks to determine a long-term rate of return for new assets.

Like rail, the BRCP requires the establishment of a long-term WACC, which is updated annually, for application to new assets. Therefore, it is reasonable to use the debt risk premium at a point in time, rather than a 10-year trailing average.

The ERA uses a 10-year bond term. Ten years is the longest feasible term that could be reliability estimated from the observed data. In Australia there is a limited market for corporate bonds for more than 10 years, which makes estimating a long-term yield curve difficult.

To calculate the debt risk premium for the BRCP the ERA supports:

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70 ERA, *Final Gas Rate of Return Guidelines Explanatory Statement*, December 2018, Chapter 10.

71 ERA, *Final Determination 2018 and 2019 Weighted Average Cost of Capital for the Freight and Urban Networks and Pilbara Railways*, August 2019, Chapter 7.3.

72 ERA, Gas Rate of Return Guidelines (online) (accessed March 2020).

- The use of the ERA revised bond yield approach. Tools, including Excel spreadsheets, are available on the ERA's website.[73]
- The use of a corporate bond that has a 10-year term, which is consistent with the long-term nature of a generator and the intent to establish a long-term WACC.
- The continued use of a benchmark sample of BBB corporate bonds.
- The use of a 10-year Government bond as the risk free rate for calculating the debt risk premium.
- The use of an on-the-day debt risk premium.
- The debt risk premium being updated annually to reflect market conditions.

3.9 Debt-raising costs

Debt-raising costs are the administrative costs and other charges incurred by businesses when obtaining finance. Debt-raising costs should only include direct costs, which will be compensated in proportion to the average annual debt issuance.

Section 2.9.8 of the market procedure set debt issuance costs at 0.125 per cent of the amount of debt. This parameter is to be reviewed every five years.

For the 2020 BRCP calculation, AEMO used an allowance of 0.125 per cent for debt issuance costs.[74]

3.9.1 The ERA's approach

The ERA has accepted that it is reasonable to recover the direct costs of debt-raising as recommended by the Allen Consulting Group in its 2004 report to the Australian Competition and Consumer Commission. Australian regulators have generally accepted the recommendations in this report.[75]

For its gas rate of return guidelines and the rail WACC final determination, the ERA adopted an allowance of 0.100 per cent for debt-raising costs. The ERA reviewed the historic use of 0.125 per cent and found that this number included a double counting error. The ERA subsequently revised debt-raising costs down to 0.100 per cent. [76]

Consistent with the ERA's rail final determination and past practice for BRCP, the ERA does not consider that an allowance for financial hedging costs is warranted for estimating a WACC for BRCP.

- As asset lives are long, firms have more certainty about the future and can enter into long-term funding arrangements, which reduces the need for an efficient entity to hedge refinancing.
- Unlike some other regulated industries, the BRCP is not subject to periodic regulatory revenue resets of the WACC (for example, five-year revenue determinations for gas pipelines). Therefore, for the BRCP, there is no need to hedge for revenue resets.

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73 Ibid.

74 AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, p. 21.

75 ERA, *Final Gas Rate of Return Guidelines Explanatory Statement*, December 2018, p. 237.

76 ERA, *Final Determination 2018 and 2019 Weighted Average Cost of Capital for the Freight and Urban Networks and Pilbara Railways*, August 2019, pp. 32-34.

The ERA supports:

- Setting debt-raising costs to 0.100 per cent.
- Fixing the debt issuance cost allowance until the next BRCP review.

Amendment 3: Updated debt issuance cost

The ERA proposes to update debt issuance costs to 0.100 per cent in section 2.9.8.

3.10 Gearing ratio

The gearing ratio is the proportion of a business's assets assumed to be financed by debt. Gearing is defined as the ratio of the value of debt to total capital (that is, including debt and equity) and used to weight the costs of debt and equity when the regulated WACC is determined. A regulatory gearing estimate contributes to a rate of return that reflects efficient financial costs. The higher level of risk an industry has the lower its general levels of gearing will be.

Section 2.9.8 of the market procedure details gearing (debt to total assets ratio) of 40 per cent, which is to be reviewed every five years.

For the 2020 BRCP calculation, AEMO adopted a gearing ratio of 40 per cent.[77]

3.10.1 The ERA's approach

The BRCP uses a gearing ratio of 40 per cent as an efficient benchmark.

The ERA considers that the benchmark provides incentives to service providers to adopt efficient gearing structures and prevents exposing consumers to the variability of individual service providers' gearing levels.

In reviewing gearing the ERA has considered data from the available benchmark sample of Australian listed generators.

There are two listed Australian generators available, AGL Energy and Infigen Energy. A third generator, Energy Developments Ltd, was available in the past and some of its past financial data is still available. The ERA's gearing analysis is presented in Table 2.

Table 2: ERA gearing analysis as at June 2020*

	Gearing 5 year average	Gearing 10 year average
AGL Energy	0.23	0.27
Infigen Energy	0.52	0.68
Energy Developments Ltd#	n/a	0.36
Average	0.37	0.44

[77] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, p. 21.

* *Source: Annual reports and ERA analysis. Gearing is calculated as debt to total capital (that is, including debt and market value of equity).*

\# *Data is available for Energy Developments Ltd for 2013 to 2015.*

The analysis has produced a gearing range between 0.23 to 0.68, which confirms that gearing of 40 per cent is still reflective of current data. The comparison of the 10 year average and 5 year average appears to indicate that gearing has been reducing slightly over time.

The BRCP uses a gearing ratio of 40 per cent to reflect the financing structure of an efficient generator. This compares to a higher gearing ratio of 55 per cent in the gas rate of return guidelines for regulated gas pipelines. The lower gearing for a generator reflects that these businesses are exposed to more risk than a regulated gas pipeline.

For the BRCP, the ERA continues to support the gearing ratio of 40 per cent in the market procedure.

3.11 Inflation rate

Inflation is the rate of change in the general level of prices of goods and services. A nominal rate of return incorporates the real rate of return, compounded with a rate that reflects expectations of inflation.

For the purposes of the calculation of the WACC, the market procedure details how the expected inflation should be determined.

> 2.9.7 (k) i [inflation] is the forecast average of inflation for the 10 year period from the date of determination of the WACC. In establishing a forecast of inflation, the IMO must have regard to the forecasts of the Reserve Bank of Australia and, beyond the period of any such forecasts, the mid-point of the Reserve Bank's target range of inflation.

Section 2.9.8 of the market procedure also details that the expected inflation is reviewed annually.

3.11.1 Stakeholder comments

In its 2020 BRCP report, AEMO noted that a negative real risk free rate, and subsequently a low WACC, did not reflect Australian market conditions at that point in time.[78] AEMO also noted that market participants queried the WACC method and provided this information to the ERA for consideration in the five-yearly review of the market procedure.[79, 80]

[78] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, pp. 12, 14.

[79] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, p. 14.

[80] Alinta Energy, *Submission to AEMO Draft Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year,* October 2019.

Alinta stated that the overestimated inflation rate used in the most recent determination contributed to the underestimated WACC. Alinta supported the ERA's further analysis of options to rectify this issue, including using a nominal WACC or reforming the method to forecast inflation.[81] The Australian Energy Council also noted a review of the inflation component would be especially useful.[82]

3.11.2 The ERA's approach

The current market procedure's approach to forecasting inflation uses:

- The Reserve Banks of Australia's annual estimates of inflation over the next two years.
- The mid-point of the Reserve Bank of Australia's 2 per cent to 3 per cent inflation target range (2.5 per cent) for the remaining eight years of the forecast period.

The large weight placed on the mid-point of the inflation target leads to a relatively static forecast of inflation of around 2.3 per cent. Using the market procedure, for the 2020 BRCP AEMO forecast inflation as 2.36 per cent.[83]

The resulting high inflation forecast is not reflective of the current low inflation environment being experienced in Australia.

- The Reserve Bank of Australia expects that inflation will average between 1 and 1.5 per cent over the next few years.[84]
- 10-year bond yields have built in expected inflation around 1.2 per cent.[85]

The inflation forecast from the market procedure is then used to discount the nominal WACC to calculate a real WACC. As the nominal WACC includes lower market expectations of inflation, the current market procedure leads to very low real WACCs that have been identified by stakeholders.

As detailed earlier, the ERA supports the use of a nominal WACC. The adoption of a nominal WACC will address stakeholders' and AEMO's concern that current negative real risk free rates and low real WACCs do not reflect Australian market conditions. Moving to a nominal WACC approach removes the need to forecast inflation, as the market's expectations are already built into a nominal WACC.

The ERA assessed inflation forecast methods, including the approach currently detailed in the market procedure, in its consideration of the 2018 gas rate of return guidelines and its rail determinations.[86, 87]

Where the ERA is required to forecast inflation for the purposes of the WACC, the ERA considers it appropriate to use the Treasury bond implied inflation approach. The Treasury

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81 Alinta Energy, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

82 Australian Energy Council, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

83 AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, p. 21.

84 RBA, *Statement by Philip Lowe, Governor: Monetary Policy Decision*, 4 August 2020 (online).

85 Based on ERA analysis of 10-year government bonds using the Treasury bond implied inflation approach, discussed below. The ERA used the same October 2019 averaging period used for 2020 BRCP calculations.

86 ERA, *Final Gas Rate of Return Guidelines Explanatory Statement*, December 2018, Chapter 15.

87 ERA, *Final Determination 2018 and 2019 Weighted Average Cost of Capital for the Freight and Urban Networks and Pilbara Railways*, August 2019, Chapter 10.

bond implied inflation approach is based on the premise that the yield on Commonwealth Government Securities and the yield on Indexed Treasury bonds differ by an inflation component.

The ERA uses the Fisher equation and the observed yields of the following bonds to calculate forecast inflation:

- Commonwealth Government Securities, which reflect a market-based estimate of the nominal risk free rate.
- Indexed Treasury bonds, which reflect a market-based estimate of a real risk free rate.

The Fisher equation can be expressed in the equation below:

$$\pi = \frac{(1 + R_f)}{(1 + R_{Rf})} - 1$$

where:

π	is the expected inflation rate
R_f	is the 10-year nominal risk free rate of return estimated on Treasury bonds
R_{Rf}	is the 10-year real risk free rate of return estimated on Treasury indexed bonds.

The use of a 10-year term for both bonds is consistent with establishing a long-term WACC.

The ERA supports the Treasury bond implied inflation approach as:

- It uses both nominal and real risk free rates directly observed in the market, which includes information on the market's view of the expected inflation rate. The rationale for using market-based approaches is that market prices reflect the aggregation of diverse market participant expectations.
- It is a dynamic market measure that is updated daily.
- It is not driven by static policy targets.
- It is consistent with market forecasts built into other WACC parameters.

In its 2020 BRCP report AEMO, using the market procedure, calculated an expected inflation forecast of 2.36 per cent.[88] Using an average period consistent with the 2020 BRCP report and the Treasury bond implied inflation approach, the ERA calculates an expected inflation of 1.23 per cent.

At present AEMO applies the real WACC in its annuity calculation, which then is used to calculate the BRCP. The use of a real WACC means that the estimate of the inflation forecast plays an important role in determining the BRCP.

- An overestimated inflation forecast will reduce the real WACC and therefore reduce the BRCP.
- An underestimated inflation forecast will increase the real WACC and therefore increase the BRCP.

[88] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, p. 21.

The move to a nominal WACC will remove the need to forecast inflation and therefore remove the effect of over or under estimation of inflation on the BRCP.

Amendment 4: Removal of inflation forecast for WACC purposes

With the proposed move to a nominal WACC, the ERA proposes to remove the need to forecast inflation for the purposes of the WACC by removing 2.9.7(k).

3.12 Value of imputation credits (gamma)

The imputation tax system prevents corporate profits from being taxed twice. Under the Australian imputation tax system, franking credits are distributed to investors at the time that dividends are paid and provide an offset to those investors' taxation liabilities.

The gamma parameter accounts for the reduction in the effective corporate taxation that arises from the distribution of franking credits to investors. Generally, investors who are able to use franking credits will accept a lower required rate of return, before personal tax, on an investment that has franking credits, compared with an investment that has similar risk and no franking credits.

Gamma is commonly estimated through the Monkhouse formula as the product of the distribution rate and the utilisation rate, as follows:[89]

gamma = distribution rate x utilisation rate

The distribution rate represents the proportion of imputation credits created that is expected to be distributed to investors. The distribution of franking credits differs amongst companies, primarily as a result of differences in shares of profit that are liable for taxation and the proportion of profits paid as dividends. As a consequence of this variability, the value of gamma required for use in the energy WACC is difficult to identify.

The utilisation rate is the weighted average of the utilisation rates of individual investors, with investors able to fully use the credits having a rate of 1 and those unable to use them having a rate of zero.

The market procedure 2.9.8 details a gamma of 0.25 and for it to be reviewed every five years.

For the 2020 BRCP calculation, AEMO adopts a gamma of 0.25.[90]

3.12.1 Stakeholder comments

Synergy provided a submission that discussed gamma. Synergy did not consider the use of top 50 Australian Securities Exchange-listed companies reflective of the characteristics of the energy industry and suggested that the existing gamma of 0.25 be retained.[91]

[89] Officer, B., *The cost of capital of a company under an imputation tax syste*m, Accounting and Finance, May 1994.

[90] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, p. 21.

[91] Synergy, *ERA's review of the Market Procedure: Benchmark Reserve Capacity Price,* September 2020, p. 2, (online).

3.12.2 The ERA's approach

In its energy and rail WACC reviews the ERA considered that it was necessary to update the past gamma approach used as:[92,93]

- Contemporary Tribunal and Federal Court judicial reviews supported the use of the utilisation approach.
- Australian Tax Office data should not be applied to all aspects of the imputation system. This was confirmed by the opinions expressed by the ATO.
- New reports and analysis presented new methods and numbers to inform improved calculations of gamma.

3.12.2.1 Gamma reviews

The estimate of gamma has been the subject of some contention in past Australian regulatory decisions, with regulated businesses consistently proposing a gamma value of 0.25, and the ERA and AER setting a value of 0.40.

There has also been contention about the definition of the value of franking credits.

The Australian Competition Tribunal conducted several limited merits reviews on the estimate of gamma under the National Electricity Rules and National Gas Rules, with the following outcomes:

- In February 2016, the Tribunal found in favour of the New South Wales networks Ausgrid, Endeavour Energy and Essential Energy that gamma should be 0.25. In March 2016, the AER applied to the Federal Court for judicial review of the Tribunal decisions to set aside the New South Wales and Australian Capital Territory electricity and gas distribution network revenue determinations. In May 2017, the full Federal Court upheld the AER's appeal in respect of the Tribunal's construction of the rules regarding gamma.[94]
- In June 2016, the Tribunal found in favour of ATCO that gamma should be 0.25. At that time there was no final determination of the full Federal Court appeal of the AER decision.
- In October 2016, the Tribunal found in favour of the AER against SA Power Networks, that gamma should be 0.4. SA Power Networks appealed the Tribunal decision to the Federal Court. In January 2018, the full Federal Court affirmed the AER's decision on gamma for a value of 0.4.[95]
- DBNGP appealed the ERA's gamma decision for its access arrangement decision. In July 2018, the Tribunal dismissed the application for merits review.

Contemporary Tribunal and Federal Court judicial reviews all upheld the reasoning in the regulators' decisions and found no error with the value of 0.4 and how it was derived.

92 ERA, *Final Gas Rate of Return Guidelines Explanatory Statement*, December 2018, Chapter 16.

93 ERA, *Final Determination 2018 and 2019 Weighted Average Cost of Capital for the Freight and Urban Networks and Pilbara Railways*, August 2019, Chapter 9.

94 Federal Court of Australia, Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79, May 2017.

95 Federal Court of Australia, SA Power Networks v Australian Competition Tribunal (No 2) [2018] FCAFC 3, Jan 2018.

This included clarification of the definition of value and gamma and the reasonableness of the use of the utilisation approach.

The ERA considered that these regulatory decisions and legal reviews were relevant to its considerations on the method of how to estimate gamma for energy and rail. These reviews confirmed the ERA's utilisation approach as appropriate.

3.12.2.2 Taxation statistics

The consideration of taxation statistics has been part of past regulatory determinations of gamma.

As part of the AER's 2018 review of its rate of return guidelines, it sought clarification from the ATO on the use of tax statistics to estimate gamma.

The ATO provided information that taxation statistics data should not be applied to all aspects of the imputation system.[96]

Given the credibility of the ATO data and the opinion expressed by the ATO, the ERA considered that ATO data should not be used to determine gamma.

3.12.2.3 New gamma reports

To assist with the consideration of gamma, Dr Lally provided advice to the AER and ERA over the course of 2018.[97] [98] [99]

Dr Lally's reports:

- Confirmed ATO data should not be used to estimate gamma.
- Confirmed that the distribution rate should be estimated from financial statement data. This distribution rate should be estimated with a large set of firms and firms should be selected on the basis of market cap.
- Undertook distribution rate analysis from the largest 50 ASX companies. The estimate of 89 per cent provided a lower bound for the distribution rate. The best estimate for the distribution rate for an Australian firm with minimal foreign operations was 0.95 rounded to the nearest 0.05.
- Stated that the utilisation rate should be defined as the weighted average over the utilisation rates of all investors in the Australian market. If account was taken of foreign investors, the best estimates came from the ABS data on the proportion of Australian equities owned by local investors. The best estimate for the utilisation rate was 0.65 rounded to the nearest 0.05.

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96 ATO, 'Re: Franking account balance – tax of time series data from Taxation Statistics', [note] 9 May 2018, (online).

See also: AER, 5 July 2018, 'AER minute of 21 June 2018 ATO meeting with ATO staff and comments on ENA summary', (online).

See also: ATO, 'Re: Franking account balance – tax of time series data from Taxation Statistics', [note] 14 September 2018, (online).

97 Lally, M., *Review of gamma submission and the ERAWA's views on gamma,* 25 July 2018.

98 Lally, M., *Estimating the Distribution Rate for Imputation Credits for the Top 50 ASX Companies*, October 2018.

99 Lally, M., *The Estimation of Gamma: Review of Recent Evidence*, December 2018.

3.12.2.4 Recommended gamma

The ERA estimates gamma as the product of the distribution rate and the utilisation rate to provide a gamma of 0.5. [100,101]

- The distribution rate represents the proportion of imputation credits generated by a benchmark efficient entity that is expected to be distributed to investors. The ERA considers that the distribution rate is a firm-specific rather than a market-wide parameter. The ERA uses a distribution rate of 0.9 informed by the distribution rate from financial reports of the 50 largest Australian Securities Exchange-listed firms. The ERA considers that this is the best proxy for the distribution rate for energy businesses.
- The utilisation rate is the weighted average over the utilisation rates of individual investors, with investors able to fully use the credit having a rate of 1 and those unable to use them having a rate of zero. The ERA uses a utilisation rate of 0.6 based on the equity ownership approach to determine the percentage of domestic investors in the Australian equity market.

The ERA supports:

- Updating gamma to 0.5.
- Fixing the value of gamma until the next BRCP review.

Amendment 5: Updated franking credit value

The ERA proposes to update the franking credit value to 0.50 per cent in section 2.9.8.

100 ERA, *Final Gas Rate of Return Guidelines Explanatory Statement*, December 2018, Chapter 16.

101 ERA, *Final Determination 2018 and 2019 Weighted Average Cost of Capital for the Freight and Urban Networks and Pilbara Railways*, August 2019, Chapter 9.

4. Illustrative rate of return for the BRCP

This section illustrates the effect that the ERA's proposed changes to the BRCP WACC will have relative to AEMO's recent 2020 calculation for the 2022-23 capacity year.

Table 3: Illustrative rate of return for BRCP

	Final Report for 2020[102]	Proposed market procedure change
Nominal risk free rate (%)	0.98	0.98
Expected inflation (%)	2.36	n/a
Market risk premium (%)	6.0	5.9
Equity beta	0.83	0.83
Debt risk premium (%)	2.23	2.23
Debt issuance costs (%)	0.125	0.100
Corporate tax rate (%)	30	30
Franking credit value	0.25	0.50
Debt to total assets ratio (%)	40	40
Pre-tax nominal WACC (% per annum)	5.95	**5.47**
Pre-tax real WACC (% per annum)	**3.51**	n/a

Table 3 details the WACC calculation for the same period based on the current and proposed WACC process.

- The current procedure applies a 3.51 per cent rate of return to the annuity calculation.
- The proposed method would apply a 5.47 per cent rate of return to the annuity calculation.

Alinta and the Australian Energy Council in their submissions to the BRCP market procedure change raised concern that the most recent BRCP WACC of 3.51 per cent significantly understates the risks faced by generation investors in the SWIS. They noted that the rate provided returns lower than rates provided to regulatory networks.[103,104] Perth Energy also agreed that the most recently developed WACC did not appear to be appropriate.[105] Synergy

[102] AEMO, *Final Report: 2020 Benchmark Reserve Capacity Price for the 2022-23 Capacity Year*, December 2019, pp. 14, 21.

[103] Alinta Energy, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

[104] Australian Energy Council, *Review of market procedure: benchmark reserve capacity price,* September 2020 (online).

[105] Perth Energy, *Benchmark Reserve Capacity Price,* August 2020 (online).

stated that the current WACC did not sufficiently compensate investors to trigger new investment.[106]

The ERA considers that the proposed market procedure and a rate of 5.47 per cent is a better estimate of the cost of capital for a generation investment.

The BRCP market procedure will continue to review market parameters of the WACC annually. As a result, the annual update of the WACC will account for changing market conditions and provide the best estimate of efficient financing costs at the point of the BRCP calculation.

[106] Synergy, *ERA's review of the Market Procedure: Benchmark Reserve Capacity Price,* September 2020, p. 2, (online).

Appendix 1 Marked up copy of the market procedure indicating the proposed changes

~~Red strikethrough text~~ represents deleted text and blue underline text represents inserted text.

Market Procedure: benchmark reserve capacity price (version 7)

PROCEDURE OVERVIEW

1.1 Relationship with the Market Rules

1.1.1 This Market Procedure for Determination of the Maximum Reserve Capacity Price should be read in conjunction with clause 4.16 of the Wholesale Electricity Market (WEM) Rules (Market Rules) and is made in accordance with clause 4.16.3 of the Market Rules.

1.1.2 References to particular Market Rules within this Procedure in bold and square brackets **[Clause XX]** are current as of 1 November 2012. These references are included for convenience only and are not part of this Procedure.

1.2 Purpose of this Procedure

1.2.1 This Procedure describes the methodology that the IMO must use and the steps that the IMO must undertake in determining the Maximum Reserve Capacity Price in each Reserve Capacity Cycle.

1.3 Application of this Procedure

1.3.1 In this Procedure where obligations are conferred on a Rule Participant that Rule Participant must comply with the relevant obligations in accordance with clauses 2.9.6, 2.9.7 and 2.9.8, as applicable.

1.4 Associated Market Procedures

1.4.1 The following IMO Market Procedures are associated with this Procedure:

(a) Balancing Facility Requirements.

1.4.2 The following System Management Power System Operation Procedures are associated with this Procedure:

(a) Communications and Control Systems.

1.5 Conventions used

1.5.1 In this Procedure the conventions specified in clauses 1.3 - 1.5 of the Market Rules apply.

1.6 Terminologies and Definitions

A word or phrase defined in the Market Rules, the Electricity Industry Act or the Regulations has the same meaning when used in this Procedure. In addition the following defined terms have the meaning given below.

Term	Definition
Access Offer	Has the same meaning as in the Electricity Networks Access Code 2004
Contribution Policy	Has the same meaning as in the Electricity Networks Access Code 2004.
Declared Sent Out Capacity	Has the same meaning as in the Electricity Networks Access Code 2004
Power Station	Means the theoretical power station upon which the Maximum Reserve Capacity Price is based, described in step 2.1 of this Procedure.
Total Transmission Costs	Means the costs to directly connect a generator to the transmission network and to augment the shared transmission network to accommodate the capacity of that generator, which are estimated in step 2.4 of this Procedure

2 DETERMINATION AND ANNUAL REVIEW OF THE MAXIMUM RESERVE CAPACITY PRICE

2.1 Definition of Power Station

2.1.1 The Power Station upon which the Maximum Reserve Capacity Price is based must:

(a) be representative of an industry standard liquid-fuelled Open Cycle Gas Turbine (OCGT) power station;

(b) have a nominal nameplate capacity of 160 MW prior to the addition of any inlet cooling system;

(c) operate on distillate as its fuel source; (d) have a capacity factor of 2%;

(e) include low Nitrous Oxide (NOx) burners or associated technologies as would be required to demonstrate good practice in power station development;

(f) include an inlet air cooling system and water receival and storage facilities to allow 14 hours of continuous operation, where in the opinion of the IMO this would be cost effective; and

(g) include the minimum level of equipment or systems required to satisfy the Balancing Facility Requirements.

2.2 Scope of the Factors to Maximum Reserve Capacity Price

2.2.1 The Maximum Reserve Capacity Price must include all reasonable costs expected to be incurred in the development of the Power Station, which must include estimation and determination of:

(a) Power Station balance of plant costs, which are those other ancillary and infrastructure costs that would normally be experienced when developing a project of this nature;

(b) land costs;

(c) costs associated with the development of liquid fuel storage and handling facilities;

(d) costs associated with the connection of the Power Station to the bulk transmission system;

(e) allowances for legal costs, insurance costs, financing costs and environmental approval costs;

(f) reasonable allowance for a contingency margin; and

(g) estimates of fixed operating and maintenance costs for the Power Station, fuel handling facilities and the transmission connection components.

2.3 Development of Costs for the Power Station

2.3.1 The IMO must engage a consultant to provide:

(a) an estimate of the costs associated with engineering, procurement and construction of the Power Station as at April in Year 3 of the Reserve Capacity Cycle;

(b) a summary of any escalation factors used in the determination; and

(c) likely output at 41°C which will take into account available turbine and inlet cooling technology, likely humidity conditions and any other relevant factors, which represents the expected Capacity Credit allocation for the Power Station.

2.3.2 The Power Station costs must be determined with specific reference to the use of actual project-related data and must take into account the specific conditions under which the Power Station will be developed. This may include direct reference to:

(a) Existing power stations, or power station projects under development, in Australia and more particularly Western Australia.

(b) Worldwide demand for gas turbine engines for power stations.

(c) The engineering, design and construction, environment and cost factors in Western Australia.

(d) The level of economic activity at the state, national and international level.

2.3.3 Development of the Power Station costs must include components for the gas turbine engines, and all Balance of Plant costs that would normally be applicable to such a Power Station. This must include, but will not be limited to the following items:

(a) Civil Works.

(b) Mechanical Works.

(c) Electrical Works.

(d) Buildings and Structures.

(e) Engineering and Plant Setup.

(f) Miscellaneous and other costs.

(g) Communications and Control equipment.

(h) Commissioning Costs.

2.4 Transmission Connection Works

2.4.1 Western Power must provide an estimate of the Total Transmission Costs in accordance with the methodology herein to connect the generator and deliver the output to loads consistent with the relevant planning criteria in the Technical Rules. The estimated Total Transmission Costs must be derived from capital contributions (either paid historically or expected to be paid to Western Power under Access Offers and Western Power's Contribution Policy as approved by the Economic Regulatory Authority) only for generators that are capable of being gas or liquid fuelled. The calculation must exclude any Facility where, in the opinion of Western Power:

- the significant driver for the location of the Facility is the access to source energy (fuel or renewable) or the need to embed the generation with a load (electrical or heat). For clarity, this includes but is not limited to coal, renewable and embedded (including waste heat capture) generators;
- the Facility is connected on a shared distribution feeder; or the capital contribution does not relate to a significant increase in the Declared Sent Out Capacity associated with the Facility.

Western Power may seek clarification from the IMO with regard to the inclusion or exclusion of specific projects in line with the above criteria.

For the purpose of the calculation, the un-escalated dollar value of the capital contribution for a Facility must be attributed to the Capacity Year for which the Facility is first assigned, or expected to be assigned, Capacity Credits and must be assumed to be in the dollars as at 1 October of that Capacity Year.

The estimate of Total Transmission Costs must use the following process:

(a) Historic and forecast capital contribution data must be collated for all works required to connect relevant generators to the transmission network including:

i. all transmission connection works required to connect from the high voltage (HV) bus bar (or in the absence of a HV bus bar, the HV circuit breaker or terminals of generator step-up transformers) to the shared transmission network (including all miscellaneous costs such as procuring land easements etc.); and

ii. all transmission works to reinforce the shared transmission network where required in accordance with the Access Code and the Technical Rules.

Capital contributions paid or forecast to be paid to Western Power may not have been calculated to cover the cost of all connection assets required to connect from the HV bus bar (or in the absence of a HV bus bar, the HV circuit breaker or

terminals of generator step-up transformers) to the shared transmission network. In this case, Western Power must identify the connection assets that have not been covered in the capital contribution and must add to the capital contribution its estimate of the cost to construct the assets based on:

i. the actual length and route of transmission or distribution lines;

ii. the actual line voltage;

iii. sufficient capacity to allow for transmission of the Certified Reserve Capacity (actual or anticipated) of the Facility;

iv. the terrain described in step 2.4.2(e); and

v. an estimate of the easement costs described in step 2.4.2(h)

(b) For years for which no historic capital contribution data or Access Offers for relevant generators are available, a connection cost must be calculated on the basis defined in step 2.4.2. For this purpose it is assumed that the costs of the works described in step 2.4.2 are fully borne by the connecting generator and the cost to reinforce the shared transmission network is assumed to be zero.

(c) The sum of connection costs for each Capacity Year must be divided by the sum of the generators' Certified Reserve Capacity to provide an "average per unit capacity" connection cost for each year. The quantity of Certified Reserve Capacity for a Facility will be the level most recently assigned to that Facility that is attributable to that capital contribution. Western Power may consult with the IMO to confirm the appropriate quantity of Certified Reserve Capacity for each Facility.

The average per unit capacity cost must be determined for the "Latest Offer Year", being the year which is the later of:

i. the latest Capacity Year for which a capital contribution has been determined or an Access Offer has been made; and

ii. the Capacity Year commencing in Year 1 of the relevant Reserve Capacity Cycle.

The average per unit capacity cost must also be determined for each of the 4 Capacity Years immediately preceding the Latest Offer Year.

(d) The five average per unit capacity costs determined in (c) must be escalated to 1 April of Year 3 of the relevant Reserve Capacity Cycle. The basis of escalation must be the average change over 5 years in the estimates calculated consistent with step 2.4.2. Where 5 years of data calculated on a common basis is not available the escalation rate must be averaged over the period for which equivalent data is available.

(e) The escalated per unit capacity costs from (d) must be multiplied by the corresponding weighting factors in the table below:

Year	Weighting
Latest Offer Year	7
Latest Offer Year - 1	5
Latest Offer Year - 2	3
Latest Offer Year - 3	1
Latest Offer Year – 4	1

The sum of the 5 years of weighted, escalated, average per unit capacity costs for the 5 years under consideration must be divided by 17 to provide a weighted escalated average per unit connection cost.

(f) The weighted escalated average per unit cost must be scaled up by 15% as an allowance for forecasting error margin to provide the forecast connection cost.

(g) Western Power must appoint a suitable auditor to review the application of the process in step 2.4.1 on an independent and confidential basis. Western Power must provide the advice of the auditor to the IMO together with its estimate of Total Connection Costs, and the IMO must publish the auditor's advice on the Market Web-site.

2.4.2 For the purposes outlined in step 2.4.1, Western Power must also estimate the cost of transmission connection works required to connect from the HV bus bar to the shared transmission network using the following process:

(a) The capital cost (procurement, installation and commissioning, excluding land cost) of a generic, industry standard 330kV substation that facilitates the connection of the Power Station must be estimated.

(b) The estimate must include all the components and costs associated with a standard substation.

(c) The estimated cost must be based on a generic three breaker mesh substation configured in a breaker and a half arrangement.

(d) It must be assumed that the substation is located adjacent to an existing transmission line and include an allowance for 2km of 330kV overhead single circuit line to the power station that will have one road crossing.

(e) It must be assumed that the transmission connection to the Power Station will be located on 50% flat - 50% undulating land, 50% rural - 50% urban location and that there will be no unforeseen environmental or civil costs associated with the development.

(f) It must be assumed that the connection of the substation into the existing transmission line is turn-in, turn-out and is based on the most economical (i.e. least cost) solution. It must be assumed that the existing transmission line will not require modification to allow the connection with the exception of one new tower located at the substation to allow a point of connection.

(g) Costs associated with any staging works must not be considered.

(h) Shallow connection easement costs will be included and must be estimated and provided by the IMO.

2.5 Fixed Operating and Maintenance Costs

2.5.1 The IMO must determine Fixed Operating and Maintenance (O&M) costs for the Power Station and the associated transmission connection works. The IMO may engage a consultant to assist the IMO in this process.

2.5.2 The Fixed O&M costs may be separated into those costs associated with the Power Station, those costs associated with the transmission connection infrastructure and any other major components that are considered likely to be of sufficient magnitude so as to require separate determination.

2.5.3 Fixed O&M costs must also include:

(a) fixed network access and/or ongoing charges, which are to be provided by Western Power; and

(b) an estimate of annual insurance costs as at 1 October in Year 3 of the relevant Reserve Capacity Cycle in respect of power station asset replacement, business interruption and public and products liability insurance as required under network access arrangements with Western Power.

2.5.4 To assist in the computation of annualised Fixed O&M costs, the costs associated with each major component will be presented for each 5 year period up to 60 years.

2.5.5 The Fixed O&M costs must be converted into an annualised Fixed O&M cost as required under the determination methodology in section 1.14.

2.5.6 Fixed O&M costs must be determined as at 1 October in Year 3 of the Reserve Capacity Cycle. Where Fixed O&M costs have been determined at a different date, those costs must be escalated using the following escalation factors which must be applied to relevant components within the Fixed O&M cost:

(a) a Generation O&M Cost escalation factor for Generation O&M costs;

(b) a Labour cost escalation factor for transmission and switchyard O&M costs; and

(c) CPI for fixed network access and/or ongoing charges determined with regard to the forecasts of the Reserve Bank of Australia and, beyond the period of any such forecasts, the mid-point of the Reserve Bank's target range of inflation.

2.6 Fixed Fuel Cost

2.6.1 The IMO must engage a consultant to determine an estimate of the costs for the Liquid Fuel storage and handling facilities including:

(a) A fuel tank of 1,000 t (nominal) capacity including foundations and spillage bund.

(b) Facilities to receive fuel from road tankers; and

(c) All associated pipework, pumping and control equipment.

2.6.2 The estimate should be based on the following assumptions:

(a) Land is available for use and all appropriate permits and approvals for both the power station and the use of liquid fuel have been received; and

(b) Any costing components that may be time-varying in nature must be disclosed by the IMO. Such components might be the cost of the liquid fuel, which will vary over time and as a function of exchange rates etc.

2.6.3 The costing must only reflect fixed costs associated with the Fixed Fuel Cost (FFC) component and must include an allowance to initially supply fuel sufficient to allow for the Power Station to operate for 14 hours at maximum capacity.

2.6.4 Fixed Fuel Costs (FFC) must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where Fixed Fuel Costs have been determined at a different date, those costs must be escalated using the annual CPI cost escalation factor determined in step 2.5.6(c).

2.7 Land Costs

2.7.1 The IMO must retain Landgate under a consultancy agreement each year to provide valuations on parcels of industrial land. The regions for which the analysis is to be conducted will include:

(a) Collie Region

(b) Kemerton Industrial Park Region

(c) Pinjar Region

(d) Kwinana Region

(e) North Country Region; and

(f) Kalgoorlie Region

These areas represent the regions within the South West interconnected system (SWIS) where generation projects are most likely to be proposed and should provide a broad cross-section of options. The IMO may include additional locations if it considers appropriate.

2.7.2 The IMO must contract with Landgate to conduct the valuations on the same land parcel size, so as to provide a consistent method of valuing the cost of purchase of the land. The IMO will provide an indication as to the size of land required, which should be limited to the following options:

(a) One 3ha parcel of land in an industrial area of a standard size with consideration given to any requirements for a buffer zone in that specific location. Where the minimum land size available in any specific location is greater than 3ha, for the purpose of calculating the land cost for that specific location, the minimum available land size at that location shall be used.

(b) The summation of multiple smaller parcels of land as appropriate to meet the requirements above.

2.7.3 Where the IMO is unable to contract with Landgate to provide the valuations described in steps 2.7.1 and 2.7.2, the IMO may seek valuations from an alternative provider of similar services.

2.7.4 The IMO must determine the average cost of the land parcels described in steps 2.7.1 and 2.7.2.

2.7.5 The average Land Cost, LC, must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where the average Land Cost has been determined at a different date this cost must be escalated using the CPI escalation factor determined in step 2.5.6(c).

2.8 Legal, Financing, Insurance, Approvals, Other Costs and Contingencies (margin M)

2.8.1 The IMO must engage a consultant to determine the value of margin M, which shall constitute the following costs associated with the development of the Power Station project:

(a) legal costs associated with the design and construction of the power station.

(b) financing costs associated with equity raising.

(c) insurance costs associated with the project development phase;

(d) approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs;

(e) other costs reasonably incurred in the design and management of the power station construction; and

(f) contingency costs.

2.9 Weighted Average Cost of Capital (WACC)

2.9.1 The IMO must determine the cost of capital to be applied to various costing components of the Maximum Reserve Capacity Price. This cost of capital must be an appropriate WACC for the generic Power Station project considered, where that project is assumed to receive Capacity Credits through the Reserve Capacity Auction and be eligible to receive a Long-Term Special Price Arrangement through the Reserve Capacity Mechanism.

2.9.2 The WACC will be applied directly:

(a) in the annualisation process used to convert the Power Station project capital cost into an annualised capital cost; and

(b) to account for the cost of capital in the time period between when the Reserve Capacity Auction is held (i.e. when capital is raised), and when the payment stream is expected to be realised. To maintain computational simplicity it is assumed that the total investment cost of the generic power station will be incurred in even incremental amounts over the 12 month period immediately preceding the first Reserve Capacity Year. As a result the effective compensation period for the total investment cost for the

generic power station will be six months as detailed in the CAPCOST formula in step 2.10.1.

2.9.3 The methodology adopted by the IMO to determine the WACC will involve a number of components that require review. These components are classed as those which require review annually (called Annual components) and those structural components of the WACC which require review less frequently (called 5 Yearly components) as detailed in step 2.9.8.

2.9.4 In determining the WACC, the IMO:

(a) must annually review and determine values for the Annual components; and

(b) may review and determine values for the 5 Yearly components that differ from those in step 2.9.8 if, in the IMO's opinion, a significant economic event has occurred since undertaking the last 5 yearly review of the Maximum Reserve Capacity Price in accordance with clause 4.16.9 of the Market Rules.

2.9.5 The IMO may engage a consultant to assist the IMO in reviewing the CAPM components of the WACC listed under step 2.9.8.

2.9.6 The IMO shall compute the WACC on the following basis:

(a) The WACC shall use the Capital Asset Pricing Model (CAPM) as the basis for calculating the return to equity.

(b) The WACC shall be computed on a Pre-Tax basis.

(c) The WACC shall use the standard Officer WACC method as the basis of calculation.

2.9.7 The pre-tax ~~real~~ Officer WACC shall be calculated using the following formulae:

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

and

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

Where:

(a) *Re* is the nominal return on equity (determined using the Capital Asset Pricing Model) and is calculated as:

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

Where:

Rf is the nominal risk free rate for the Capacity Year;

βe is the equity beta; and

MRP is the market risk premium.

(b) Rd is the nominal return on debt and is calculated as:

$$R_d = R_f + DM$$

Where:

Rf is the nominal risk free rate for the Capacity Year;

DM is the debt margin, which is calculated as the sum of the debt risk premium (DRP) and debt issuance cost (d).

(c) t is the benchmark rate of corporate income taxation, established at either an estimated effective rate or a value of the statutory taxation rate;

(d) γ is the value of franking credits;

(e) E/V is the market value of equity as a proportion of the market value of total assets;

(f) D/V is the market value of debt as a proportion of the market value of total assets;

(g) The nominal risk free rate, for a Capacity Year is the rate determined for that Capacity Year by the IMO on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years:

- using the indicative mid rates published by the Reserve Bank of Australia; and
- averaged over a 20-trading day period;

(h) The debt risk premium, DRP, for a Capacity Year is a margin above the risk free rate reflecting the risk in provision of debt finance. This will be estimated by the IMO as the margin between the observed annualised yields of Australian corporate bonds which have a BBB (or equivalent) credit rating from Standard and Poors and the nominal risk free rate. The IMO must determine the methodology to estimate the DRP, which in the opinion of the IMO is consistent with current accepted Australian regulatory practice.[107]

(i) If there are no Commonwealth Government bonds with a maturity of 10 years on any day in the period referred to in step 2.9.7(g), the IMO must determine the nominal risk free rate by interpolating on a straight line basis from the two bonds closest to the 10 year term and which also straddle the 10 year expiry date.

[107] Given observed issues with Bloomberg data, the ERA has adopted an alternative 'Bond-Yield Approach' to establishing the DRP and has applied this since its Final Decision on revisions proposed by WA Gas Networks (WAGN) to the access arrangement for the Mid West and South West gas distribution systems in 2011. This methodology was broadly upheld on appeal to the Australian Competition Tribunal in June 2012.The IMO intends to amend this Market Procedure in the near future to implement the 'Bond-Yield Approach'.

(j) If the methods used in step 2.9.7(i) cannot be applied due to suitable bond terms being unavailable, the IMO may determine the nominal risk free rate by means of an appropriate approximation.

~~(k) i is the forecast average rate of inflation for the 10 year period from the date of determination of the WACC. In establishing a forecast of inflation, the IMO must have regard to the forecasts of the Reserve Bank of Australia and, beyond the period of any such forecasts, the mid-point of the Reserve Bank's target range of inflation.~~

2.9.8 The CAPM must use the following parameters as variables each year:

CAPM Parameter	Notation/Determination	Review Frequency	Value
Nominal risk free rate of return (%)	Rf	Annual	TBD
~~Expected inflation (%)~~	~~i~~	~~Annual~~	~~TBD~~
~~Real risk free rate of return (%)~~	~~Rfr~~	~~Annual~~	~~TBD~~
Market risk premium (%)	MRP	5-Yearly	5.90 ~~6.00~~
Asset beta	βa	5-Yearly	0.5
Equity beta	Be	5-Yearly	0.83
Debt risk premium (%)	DRP	Annual	TBD
Debt issuance costs (%)	D	5-Yearly	0.100 ~~0.125~~
Corporate tax rate (%)	t	Annual	TBD
Franking credit value	Y	5-Yearly	0.50 ~~0.25~~
Debt to total assets ratio (%)	D/V	5-Yearly	40
Equity to total assets ratio (%)	E/V	5-Yearly	60

2.10 Determination of the Maximum Reserve Capacity Price

2.10.1 The IMO must use the following formulae to determine the Maximum Reserve Capacity Price:

MRCP = (ANNUALISED_FIXED_O&M + ANNUALISED_CAPCOST / CC)

Where:

MRCPis the Maximum Reserve Capacity Price to apply in a Reserve Capacity Auction;

ANNUALISED_CAPCOST is the CAPCOST, expressed in Australian dollars, annualised over a 15 year period, using a nominal Weighted Average Cost of Capital (WACC) as determined in step 2.9;

CC is the expected Capacity Credit allocation determined in conjunction with Power Station costs in step 2.3.1 (c);

CAPCOST is the total capital cost, expressed in million Australian dollars, estimated for an open cycle gas turbine power station of capacity CAP; and

ANNUALISED_FIXED_O&M is the annualised fixed operating and maintenance costs for a typical open cycle gas turbine power station and any associated electricity transmission facilities determined in step 2.5 and expressed in Australian dollars, per MW per year.

The value of CAPCOST must be calculated as:

CAPCOST = ((PC x (1 + M) + TC) x CC + FFC + LC) x (1+ WACC)^1/2

Where:

PC is the capital cost of an open cycle gas turbine power station, expressed in Australian dollars per MW as determined in step 2.3 for that location;

M is a margin to cover legal, approval, financing and other costs and contingencies as detailed in step 2.8;

TC is the estimate of Total Transmission Costs as determined in step 2.4;

CC is the expected Capacity Credit allocation determined in conjunction with Power Station costs in step 2.3.1 (c);

FFC is the Fixed Fuel Cost as determined in step 2.6;

LC is the Land Cost as determined in step 2.7; and

WACC is the Weighted Average Cost of Capital as determined in step 2.9.

2.10.2 Once the IMO has determined a revised value for the Maximum Reserve Capacity Price, the IMO must publish a draft report describing how it has arrived at the proposed revised value and undertake consultation in accordance with clause 4.16.6 of the Market Rules. In preparing the draft report, the IMO must include details of how it has arrived at any proposed revised values for the Annual and 5 Yearly components used in calculating the WACC.

2.10.3 The IMO must publish any supporting consultant reports with the draft report on the Market Web Site.

2.10.4 After considering any submissions on the draft report the IMO must propose a final value for the Maximum Reserve Capacity Price and submit the report to the Economic Regulation Authority (ERA) of Western Australia for its approval under clause 2.26.1 of the Market Rules.

2.10.5 Once the final value for the Maximum Reserve Capacity Price, with any updates, has been approved by the ERA, the IMO must publish the final report and submissions as required by clause 4.16.7 of the Market Rules.

2.10.6 The IMO must include the Maximum Reserve Capacity Price in the Request for Expressions of Interest document which must be published by the date and time specified in clause 4.1.4 of the Market Rules.

2.11 Major Review

2.11.1 In accordance with clause 4.16.9, the IMO must conduct a review of this Market Procedure containing the methodology used to determine the Maximum Reserve Capacity Price at least once every five years ("Major Review"). This process will include a review of the basis for determining the Maximum Reserve Capacity Price, the structural methodology by which the Maximum Reserve Capacity Price is computed each year and the method the IMO uses to estimate each of the constituent components of the Maximum Reserve Capacity Price.

2.11.2 In conducting the annual review of the WACC, where the IMO considers that any of the comparator companies used in the most recent Major Review are no longer available or that their characteristics have significantly changed, the IMO may select a different set of comparator companies for determination of relevant WACC parameters, applying the following criteria:

(a) the company must be a power generator, energy transmitter or distributor;

(b) market capitalisation must be more than $200m AUD; and

(c) the company must be listed on Bloomberg.