DRAFT DECISION

Ergon Energy
Distribution Determination
2020 to 2025

Attachment 3
Rate of Return

October 2019

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Ergon Energy for the 2020-2025 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

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Contents

Shortened forms

Shortened form	Extended form
ACG	Allen Consulting Group
AER	Australian Energy Regulator
bppa	basis points per annum
COAG EC	Council of Australian Governments – Energy Council
DRP	debt risk premium
ECA	Energy Consumers Australia
ERP	equity risk premium
MRP	market risk premium
NEL	national electricity law
NER or rules	national electricity rules
NSP	network service provider
opex	operating expenditure
PIAC	Public Interest Advocacy Centre
PTRM	post-tax revenue model
PwC	PricewaterhouseCoopers
RAB	regulatory asset base
RBA	Reserve Bank of Australia
SL-CAPM	Sharpe-Lintner capital asset pricing model
WACC	weighted average cost of capital
ACG	Allen Consulting Group
AER	Australian Energy Regulator
bppa	basis points per annum
CCP13	Consumer Challenge Panel, sub-panel 13
ACG	Allen Consulting Group
AER	Australian Energy Regulator
bppa	basis points per annum
CCP10	Consumer Challenge Panel, sub-panel 10
COAG EC	Council of Australian Governments – Energy Council
DRP	debt risk premium

3 Rate of Return

The return each business is to receive on its regulatory asset base (RAB), known as the ‘return on capital’, continues to be a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest on its loans and give a return on equity to investors.

An accurate estimate of the rate of return is necessary to promote efficient prices in the long-term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

The 2018 Rate of Return Instrument (2018 Instrument) specifies how we will estimate the return on debt, the return on equity, and the overall rate of return.[1] As required under the NEL, we have applied the 2018 Instrument and estimate a placeholder allowed rate of return of 4.87 per cent (nominal vanilla) which will be updated for our final decision on the averaging periods.[2] Ergon Energy's initial proposal adopted the 2018 Instrument.[3]

Our calculated rate of return, in Table 3.1, will apply to the first year of the 2020–25 regulatory control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with the 2018 Instrument to use a 10-year trailing average portfolio return on debt that is rolled-forward each year.

1 AER, *Rate of return instrument*, December 2018. See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision.

2 The legislative amendments to replace the (previous) non-binding Rate of Return Guidelines with a binding legislative instrument were passed by the South Australian Parliament in December 2018. See, Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Act 2018 (SA). NGL, Chapter 2, Part 1, division 1A; NEL, Part 3, division 1B.

3 Ergon Energy, *2020–25 Regulatory proposal*, January 2019, p. 94.

Table 3.1 Draft decision on Ergon Energy's rate of return (% nominal)

	Previous Regulatory Period (2015–20)	Ergon Energy Initial Proposal (2020–25)	AER draft decision (2020–25)	Allowed return over regulatory control period
Nominal risk free rate	2.96%	2.60%	1.32%[a]	
Market risk premium	6.5%	6.1%	6.1%	
Equity beta	0.7	0.6	0.6	
Return on equity (nominal post–tax)	7.5%	6.26%	4.98%	Constant (%)
Return on debt (nominal pre–tax)	5.01%[b]	4.92%	4.79%	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.01%[b]	5.46%	4.87%	Updated annually for return on debt
Expected inflation	2.5%	2.42%	2.45%	Constant (%)

Source: AER analysis.

[a] Calculated using a placeholder averaging period of 20 business days ending 31 July 2019.

[b] Applies to the first year of the 2015–20 regulatory control period.

Our draft decision is to accept Ergon Energy's proposed risk free rate[4] and debt averaging periods because they complied with conditions set out in the 2018 Instrument.[5]

We specify these periods in confidential appendix A and they will be used to update the risk free rate and return on debt in the final decision.

3.1 Expected inflation rate

Our estimate of expected inflation is 2.45 per cent which will be updated for the final decision. It is an estimate of the average annual rate of inflation expected over a ten year period.

We estimate expected inflation over this 10-year term to align with the term of the rate of return. Our estimate of expected inflation is estimated in accordance with the

4 This is also known as the return on equity averaging period.

5 AER, *Rate of return instrument*, December 2018, cll. 7–8, 23–25, 36; AER, *Draft decision, Ergon Energy distribution determination 2020 to 2025 Attachment 3—Rate of return confidential appendix A: Equity and debt averaging periods*, October 2019.

method set out in the post-tax revenue model. The rules set out how we are to apply the post-tax revenue model and the inflation estimation method in the model in our electricity determinations.

Ergon Energy adopted our method for estimating expected inflation.[6] Our expected inflation is estimated as the geometric average of 10 annual expected inflation rates. We use the RBA's forecasts of inflation for the first two years of Ergon Energy's 2020–25 regulatory period as the first two annual rates. We then use the mid-point of the RBA's inflation target band as the remaining eight annual rates.

3.2 Capital raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt.

On the other hand, we include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments. Our draft decision forecasts for debt and equity raising costs are included in the opex and capex attachments, respectively. In this section, we set out our assessment approach and the reasons for those forecasts.

3.3 Equity raising costs

Equity raising costs are transaction costs incurred when a service provider raises new equity. We provide an allowance to recover an efficient amount of equity raising costs.

We apply an established benchmark approach for estimating equity raising costs. This approach estimates the costs of two means by which a service provider could raise equity—dividend reinvestment plans and seasoned equity offerings. It considers where a service provider's capex forecast is large enough to require an external equity injection to maintain the benchmark gearing of 60 per cent.[7]

Our benchmark approach was initially based on 2007 advice from the Allen Consulting Group (ACG).[8] We amended this method in our 2009 decisions for the ACT, NSW and Tasmanian electricity service providers.[9] We further refined this approach in our 2012 Powerlink decision.[10]

6 Ergon Energy, *2020–25 Regulatory Proposal,* January 2019, p. 98.

7 AER, *Final decision Amendment Electricity distribution network service providers, Post-tax revenue model handbook*, 29 January 2015, pp. 15, 16 & 33. The approach is discussed in AER, *Final decision, Powerlink Transmission determination 2012–13 to 2016–17*, April 2012, pp. 151–152.

8 ACG, *Estimation of Powerlink's SEO transaction cost allowance – Memorandum*, 5 February 2007.

9 For example, see; AER, *Final decision, ACT distribution determination 2009–10 to 2013–14*, April 2009, appendix H.

10 AER, *Final decision, Powerlink Transmission determination 2012–13 to 2016–17, April 2012*, pp. 151–152.

Our benchmark approach requires an estimate of the dividend distribution rate (sometimes called the payout ratio) as an input into calculating equity raising costs. The dividend distribution rate is also estimated when we estimate the value of imputation credits. We consider that a consistent dividend distribution rate should be used when estimating both the value of imputation credits and equity raising costs. Ergon Energy appears to use our benchmark approach for estimating equity raising costs and stated that it adopts a distribution rate consistent with that estimated in the 2018 Instrument.[11] On this basis we determine zero equity raising costs for this distribution determination.

3.4 Debt raising costs

Debt raising costs are the transaction costs incurred each time debt is raised or refinanced and the costs for maintaining the debt facility. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs. We provide an allowance to recover an efficient amount of debt raising costs.

We determine debt raising costs using our benchmark based approach. Ergon Energy accepted our approach in its proposal.[12] However, as set out in the operating expenditure attachment, we accept Ergon Energy's proposed total opex allowance for its standard control services in its entirety. This includes its proposed debt raising costs of $28.52 million over the 2020–25 period as set out in Table 3.2. For this reason, we have not separately updated Ergon Energy's estimate of debt raising costs.

Table 3.2 AER's draft decision on debt raising costs ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Ergon Energy	5.62	5.66	5.71	5.75	5.78	28.52

Source: AER analysis.

Note: Columns may not add to total due to rounding for presentation in table.

While our acceptance of Ergon Energy's opex proposal settles the allowance for debt raising costs, for completeness we describe the AER's standard approach below.

AER standard estimation approach

Our standard approach to forecasting debt raising costs is based on the approach in a report from the ACG, commissioned by the ACCC in 2004.[13] We previously relied on market data from 2008–13, as submitted in a report by PricewaterhouseCoopers (PwC) during the 2013 rate of return guidelines process, to inform our allowance.[14] We

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11 Ergon Energy, *2020–25 Regulatory Proposal,* January 2019, p. 98; Ergon Energy, *RIN debt averaging and PTRM (confidential)*, January 2019.

12 Ergon Energy, *2020–25 Regulatory proposal*, January 2019, p. 97.

13 ACG, *Debt and equity raising transaction costs*: *Final report*, December 2004.

14 PricewaterhouseCoopers, *Energy Networks Association: Debt financing costs*, June 2013, p. i.

have further updated our allowance using estimates from Chairmont's 2019 report as part of our review of debt raising costs.[15]

The ACG method involves calculating the benchmark bond size, and the number of bond issues required to rollover the benchmark debt share (60 per cent) of the RAB. Our standard approach is to amortise the upfront costs that are incurred using the relevant nominal vanilla WACC over a ten year amortisation period. This is then expressed in basis points per annum (bppa) as an input into the post-tax revenue model (PTRM). This rate is multiplied by the debt component of a service provider's projected RAB to determine the debt raising cost allowance. The ACG approach recognises that credit rating costs can be spread across multiple bond issues, which lowers the benchmark allowance (as expressed in bppa) as the number of bond issues increases.

We note that, in a concurrent process, SA Power Networks' initial proposal did not accept the AER's standard approach to estimating benchmark debt raising costs. It proposed a higher annual allowance for direct debt raising costs and stated that further examination of indirect debt raising costs should occur.[16] In support of this position, it submitted a consultant report by the Competition Economists Group (CEG).[17]

This led us to review our standard approach for estimating debt raising costs which is discussed in more detail in our draft decision for SA Power Networks.[18] In summary, the material currently before us continues to support our overall approach. However, SA Power Networks' submission proposed some deficiencies in our current approach and proposed different cost categories to those in our allowance. It is not clear at this stage that this information warrants changing our benchmark allowance as there were also problems with SA Power Networks' alternative approach. This does highlight the need to supplement our approach with additional information from across the sector to further assess and update our benchmark allowance. We plan to request actual debt raising cost information from all regulated businesses to further inform our review. In the absence of other benchmark costs, we have adopted Chairmont's updated estimates to determine debt raising costs in the standard approach.

We also found that although the PTRM's timing benefits have declined with a falling WACC, they still fully compensate for CEG's proposed indirect debt raising costs. Therefore, no separate compensation is required for these costs.

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15 Chairmont, *Debt Raising Costs*, 29 June 2019.

16 Indirect costs refers to costs arising from management of liquidity and refinancing risk.

17 SAPN, *2020–25 Regulatory Proposal, Attachment 3 - Rate of return*, 31 January 2019, pp. 10–11; CEG, *Debt transaction costs and PTRM timing benefits*, January 2019 (supporting document 3.1 to the SAPN proposal).

18 AER, *Draft decision, SA Power Networks distribution determination 2020 to 25, Attachment 3 – Rate of return,* October 2019, pp. 8–18.

A Confidential Appendix (Averaging Period)