DRAFT DECISION

SA Power Networks
Distribution Determination
2020 to 2025

Attachment 3
Rate of Return

October 2019

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to SA Power Networks 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

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 14 – Pass through events

Attachment 15 – Alternative control services

Attachment 16 – Negotiated services framework and criteria

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

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 4.95 per cent (nominal vanilla) which will be updated for our final decision on the averaging periods.[2] SA Power Networks’ 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.

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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 SA Power Networks, *2020-25 Regulatory proposal*, January 2019, p. 9.

Table 3.1 Draft decision on SA Power Networks' rate of return (% nominal)

	Previous Regulatory Period (2015–20)	SA Power Networks' Initial Proposal (2020–25)	AER draft decision (2020–25)	Allowed return over regulatory control period
Nominal risk free rate	2.96%	2.44%	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%	6.1%	4.98%	Constant (%)
Return on debt (nominal pre–tax)	5.28%[b]	4.98%	4.93%	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.17%[b]	5.43%	4.95%	Updated annually for return on debt
Expected inflation	2.5%	2.47%	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 SA Power Networks' proposed risk free rate[4] and debt averaging periods[5] because they complied with conditions set out in the 2018 Instrument.[6]

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.

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

5 SA Power Networks, *RIN debt averaging and PTRM (confidential)*, 12 February 2019; SA Power Networks, *SAPN-RIN 1-Workbook 1-Regulatory determination template 2020-21 to 2024-25-January 2019-confidential*, January 2019. The February letter contained corrected debt averaging periods as SA Power Networks informed us that its initial debt averaging periods contained a typographical error.

6 AER, *Rate of return instrument*, December 2018, clauses 7–8, 23–25, 36; AER, *Draft decision SA Power Networks Distribution Determination 2020 to 2025 Attachment 3—Rate of return confidential appendix A: Equity and debt averaging periods*, October 2019.

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 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.

SA Power Networks adopted our method for estimating expected inflation.[7] 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 SA Power Networks' 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.[8]

Our benchmark approach was initially based on 2007 advice from Allen Consulting Group (ACG).[9] We amended this method in our 2009 decisions for the ACT, NSW and

7 SA Power Networks, *2020–25 Regulatory Proposal, Attachment 3 - Rate of return*, 31 January 2019, pp. 9–10.

8 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.

9 ACG, *Estimation of Powerlink's SEO transaction cost allowance – Memorandum*, 5 February 2007. T

Tasmanian electricity service providers.[10] We further refined this approach in our 2012 Powerlink decision.[11]

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. SA Power Networks has adopted our benchmark approach for estimating equity raising costs and stated that it adopts a distribution rate consistent with that estimated in the 2018 Instrument.[12] On this basis and having updated for inputs we determine zero equity raising costs for this distribution determination.

We note that while SA Power Networks' PTRM initially contained a distribution rate of 0.88, it subsequently noted that this should be 0.9 (consistent with the 2018 Instrument).

3.4 Debt raising costs

Debt raising costs are the transaction costs incurred each time debt is raised or refinanced and as well 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.

3.4.1 Current AER approach

Our current approach to forecasting debt raising costs is based on the approach in a report from the Allen Consulting Group (ACG), commissioned by the ACCC in 2004.[13] The approach uses a five year window of bond data to reflect the market conditions at that time. Our estimates were last updated in 2013 based on a report by PricewaterhouseCoopers (PwC), which used data over 2008–2013.[14]

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. This approach looks at how many bonds a regulated service provider may require to issue to refinance its debt over a 10 year period.

Our standard approach is to amortise the upfront costs that are incurred in raising the bonds using the service provider’s nominal vanilla weighted average cost of capital

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10 For example, see: AER, *Final decision, NSW distribution determination 2009–10 to 2013–14*, April 2009, appendix N.

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

12 SA Power Networks, *2020–25 Regulatory Proposal Attachment 3 Rate of Return*, 31 January 2019, p. 10; SA Power Networks, *RIN debt averaging and PTRM (confidential)*, 12 February 2019.

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

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

(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 the service provider's projected RAB to determine the debt raising cost allowance (in dollar terms). Our approach recognizes that part of the debt raising transaction costs such as credit rating costs and bond master program fees can be spread across multiple bond issues, which lowers the benchmark allowance (as expressed in bppa) as the number of bond issues increases.

3.4.2 SA Power Networks' proposal and CEG's report

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.[15] In support of this position it submitted a consultant report by the Competition Economists Group (CEG).[16]

CEG calculated a debt raising cost of 27 basis points a year composed of components in the table below.[17] Not all components from the CEG report were then proposed by SA Power Networks.

[15] Indirect costs refers to costs arising from management of liquidity and refinancing risk.

[16] SA Power Networks, *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 SA Power Networks proposal).

[17] CEG, *Debt transaction costs and PTRM timing benefits*, January 2019, p. 6.

Table 3.2 CEG debt raising cost components

Costs	Cost (basis points per annum)	Party	Details
Direct debt raising cost	9	CEG, SA Power Networks	Updated estimate of the direct raising costs using the our current approach
Difference between bonds' traded and issue price	6	CEG, SA Power Networks	A new category of direct cost
Indirect debt raising cost	12	CEG	Costs related to liquidity management and 3 months ahead financing totalling 12 basis points.[18] The liquidity management cost is the cost of establishing and maintaining bank facilities (so that funding sources are greater than uses) to attain S&P's liquidity requirements to maintain an investment grade credit rating. The 3 months ahead financing is to compensate for S&P's requirement that businesses refinance a minimum of 3 months ahead of the maturity of their existing debt.

Jemena Gas Networks (JGN) also submitted a June 2019 version of CEG's report.[19] We note that the two CEG reports are substantively the same with the June version containing updated estimates for JGN and missing a section on the PTRM's timing benefits. However, JGN proposed to adopt our approach to DRC.[20]

Therefore, our discussions and considerations are relevant and applicable to both versions of CEG's report.

3.4.3 Draft decision

Our draft decision is to maintain our current overall approach for estimating debt raising cost. We do not consider that the evidence currently before us sufficiently supports SA Power Networks' proposed allowance for debt raising costs, or the higher costs presented in CEG's report. We acknowledge that the PTRM's timing benefits have declined with a falling WACC but updated modelling indicate that they still fully compensate for CEG's calculation of indirect debt raising costs.

In the absence of other benchmark cost estimates, we have adopted Chairmont's updated estimates for this draft decision given we set a benchmark allowance. This determines debt raising costs of $7.2 million over the 2020–25 period for SA Power Networks as set out in the table below.

18 The timing assumption for cash inflows and outflows within the PTRM overall creates a bias in favour of the service providers.

19 CEG, *Debt transaction costs and PTRM timing benefits*, June 2019 (Attachment 6.6 to JGN's Access arrangement proposal 2020–25).

20 JGN, *2020–25 Access Arrangement Proposal Attachment 7.7 Rate of return*, 30 June 2019, p. 10.

Table 3.3 AER's draft decision on debt raising costs ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Debt raising costs	1.47	1.46	1.44	1.41	1.38	7.17

Source: AER analysis.

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

However, we have analysed SA Power Networks' actual debt raising costs which indicate different cost categories to those in our allowance. It is not clear at this stage that this information warrants changing our allowance, given we set a benchmark allowance. This highlighted a need to supplement our approach with additional information from across the sector to further assess and update our benchmark allowance. Chairmont also advised that actual data should be used for this purpose. Therefore, we plan to request actual debt raising cost information from all regulated businesses which will provide additional transparency on the costs an efficient provider of regulated energy services would face.

We discuss our reasons further below.

3.4.4 Assessment approach

We note that our debt raising allowance was previously updated in 2013 using estimates from PricewaterhouseCoopers (PwC).[21] Given CEG's report included three new cost categories,[22] we consider now would be an opportune time to review our approach.

We consider that there are four broad questions to the review:

- Is our overall approach still appropriate?
- Are our cost categories and estimates still appropriate?
- Should our allowance include SA Power Networks' proposed new direct cost category (for the difference between traded and issue price)?
- Do we (already) provide sufficient compensation to cover the two indirect debt raising costs calculated by CEG?

We consider each question in turn.

3.4.5 Overall approach

As noted in section 3.4.1, our current approach derives a debt raising allowance using the following broad steps:

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21 PricewaterhouseCoopers, *Energy Networks Association: Debt financing costs*, June 2013.

22 CEG proposed three new cost categories: a direct cost category (the difference between a bond's traded and issue price) and two indirect cost categories (liquidity costs and three months ahead financing costs).

- Estimate the number of bond issues required to rollover the benchmark debt share (60 per cent) of the RAB based on the benchmark issuance size ($250 million).
- Amortise/annualise costs that are incurred over a ten year period (using a business' WACC and the number of bond issues) and express in terms of basis points. This acts as an input into the post-tax revenue model (PTRM) and is multiplied by the size of a business' debt (60 per cent of the RAB) to arrive at the dollar value of our allowance.

We observe that neither Chairmont nor CEG raised concerns with our overall approach.[23] In fact both have adopted our overall approach. Therefore, we consider that our overall approach remains appropriate.

We note that Chairmont suggested two adjustments:

1) Annualise costs using the rate of return on debt and not WACC.
2) Costs considered as 'one-off' should be recovered via opex allowance and 'ongoing' costs should be recovered via debt raising allowance.

Whilst there are reasons for the suggested adjustments, we consider that our current approach remains reasonable.

On suggestion 1, we note that debt raising costs are recovered through the opex allowance and the PTRM uses the WACC to discount opex cashflows. Therefore, it would be more consistent to retain the use of WACC to annualise/amortise debt raising costs.

On suggestion 2, the current approach annualises costs (both one-off and ongoing) to recover them over 10 years in the debt raising allowance. We do not consider this would be substantially different from a one-off recovery approach (in the opex allowance) on a forward looking net present value (NPV) basis.

We currently use a benchmark issuance size of $250 million. Chairmont supported the continued use of this estimate and CEG did not identify any disagreement with this amount. Therefore, our decision is to maintain benchmark issuance at $250 million.

3.4.6 Direct cost categories and estimates

Our current allowance provides compensation for the direct cost of raising debt. To ascertain if the cost categories and estimates are still appropriate, we have considered information from CEG, Chairmont and SA Power Networks' actual debt raising costs.

Our current debt raising approach adopted direct cost estimates and categories from PwC's 2013 report.[24] We note that CEG has not raised issues with PwC's direct cost

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23 CEG, *Debt transactions and PTRM timing benefits*, January 2019, p. 6; Chairmont, *Debt Raising Costs*, 29 June 2019, p. 14.

24 PricewaterhouseCoopers, *Energy Networks Association: Debt financing costs*, June 2013.

categories and estimates (apart from proposing inclusion of a new direct cost). In fact, CEG adopted PwC's estimates. However, we consider it appropriate to review PwC's direct cost estimates because they were from 2013 and as part of our review of the three new costs in CEG's report.

Chairmont, as part of its review of our approach, provided updated estimates for our allowance. Table 3.4 compares Chairmont and PwC's total cost for each cost category. The key observation is that with the exception of arrangement fee, Chairmont's estimates for most direct costs (assuming a global issue program and the mid-point of the range) represent an increase on PwC's estimates. This does not appear unreasonable given PwC's estimates were from 2013.

Table 3.4 PwC and Chairmont direct debt raising costs

	PwC	Chairmont	Chairmont mid-point and global issue
Arrangement fee	52.3 basis points	25–35 basis points	30 basis points
Bond Master Program (per program)	$56,250	$70,000–$150,000 per 10 years	$110,000
Issuer's legal counsel	$15,625	$10,000–$50,000 either once-off or per drawdown depending on global or domestic program	$30,000
Company/initial credit rating	$77,500	$70,000–$100,000 upfront per 10 years	$85,000
Annual surveillance fee	$35,500	$10,000–$20,000 per annum in total	$15,000
Up-front issuance fee	5.20bp	5–10 bp per issue	7.5 bp
Registration up-front (per program)	$20,850	$6,000–$20,000 per 10 years	$13,000
Registration- annual	$7,825	$6,000–$7,000 per annum per issue	$6,500
Agents out-of-pockets	$3,000	$5,000–$10,000 domestic program per issue $20,000–$50,000 global program per issue	$35,000

The table below compares Chairmont's estimates against those from PwC and CEG on an annualised basis (using SA Power Networks' proposed WACC of 5.43 per cent and opening RAB). Chairmont's total estimate is below that from PwC and CEG; this lower total estimate is driven by a lower arrangement fee.

Table 3.5: Annualised PwC, CEG and Chairmont's direct cost estimates

	PwC's estimate for SA Power Networks	Chairmont's estimates for SA Power Networks	CEG estimates for SA Power Networks*
Arrangement fee	6.91	3.97	7.86*
Other direct debt raising costs			

	PwC's estimate for SA Power Networks	Chairmont's estimates for SA Power Networks	CEG estimates for SA Power Networks*
Legal Counsel- Master program	0.03	0.05	0.03
Legal counsel- issuer's	0.08	0.16	0.08
Credit rating agency- initial credit rating	0.04	0.04	0.04
Credit rating agency- annual surveillance	0.01	0.05	0.01
Credit rating agency- up front bond issue	0.69	0.99	0.69
Registrar- up front	0.01	0.01	0.01
Registrar- annual	0.31	0.26	0.31
Investment bank's out-of-pocket expenses	0.02	0.19	0.02
Total other direct debt raising cost	1.19	1.75	1.19
Total basis points per annum	8.10	5.72	9.0

* CEG stated that it adopted and updated PwC's estimates. However, we found that its arrangement fee of 7.86 bppa is based on an incorrect application of PwC's approach.

We note CEG's report stated that it followed PwC's approach to estimate an arrangement fee of 7.86 basis points.[25] However, this does not appear to be the case. PwC's approach entails broadly 3 steps:

1) Estimate initial annualised value from suitable bonds of varying maturities using an assumed WACC (10 per cent), outliers are excluded from the sample based on the annualised value.

2) The average of the annualised debt raising costs (excluding outliers) is converted to total cost (assuming 10 years) using the same WACC (10 per cent).

3) Re-annualise over 10 years at a regulated firm's nominal vanilla WACC.

Our replication of CEG's estimate indicates that its 7.86 figure is from step 1 which is inconsistent with PwC's approach.

As part of our review, we also sought actual debt raising cost information from SA Power Networks. While we have reviewed this confidential information, we have not included details in this (public) decision document.

The key observation was that SA Power Networks' actual costs contain different cost categories to those in our (and CEG and Chairmont's) allowance. However, given we set a benchmark debt raising cost allowance, it is not clear to what extent (if any) SA Power Networks' costs warrant changing our allowance. We are uncertain if they are a

25 CEG, *Debt transactions and PTRM timing benefits*, January 2019, p. 24.

reasonable reflection of costs incurred across the industry or by an Australian energy network firm with a similar degree of risk as an efficient service provider in the supply of regulated energy network services.

We consider that SA Power Networks' actual data highlighted a need to supplement our approach with additional information from across the sector to further assess and update our benchmark allowance. Chairmont also advised that actual data should be used for this purpose.

As a result, we have requested actual debt raising cost information from all regulated networks as part of our planned annual information gathering process which we envisage to provide additional transparency on the costs an efficient service provider of regulated energy services would face.

However, we set a benchmark allowance for debt raising costs. We note that SA Power Networks and CEG both adopted PwC's direct cost estimates. Following Chairmont's review, and in the absence of other benchmark estimates, our view is to adopt Chairmont's direct cost estimates for this draft decision.

3.4.7 SA Power Networks' proposed new direct debt raising cost category

Based on the CEG report, SA Power Networks proposed to include a new category of direct cost–the difference between bonds' traded and issue price–in our debt raising allowance.[26] It indicated that, in addition to the arrangement fee (paid by the issuer and the biggest component of our allowance), underwriters' compensation also comes from the difference between issue price and trading price.[27] CEG appears to assume that underwriters purchase the bonds and then sell to the public during debt raising.[28]

Having considered CEG's submission, we are not persuaded that this cost should be in the debt raising allowance. Our task is to set an efficient allowance to compensate regulated businesses for issuing debt. In terms of the cost of underwriter(s) to an issuer, that is the arrangement fee. The difference between issue price and traded price reflects a gain or loss for the underwriter, but it comes from market participants—not the issuer of the debt. It is not clear to us that there is a need to compensate for underwriters' subsequent profits and losses in a benchmark that compensates issuers. There are also a range of factors that can cause traded price to differ from issued price (such as subsequent change in interest rates, economic outlook) that do not appear to affect the arrangement fee paid by issuers.

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26 CEG, *Debt transactions and PTRM timing benefits*, January 2019, pp. 19–23.

27 In acting as an intermediary between a bond issuer and a bond buyer, the underwriter helps with managing the debt raising and sometimes also serve to underwrite the bonds. When underwriting bond issues, underwriters assume the risk of buying the newly issued bonds from the issuer and then resell (either at a profit/loss) to the public or to dealers who sell them to the public. The underwriting may be on a best efforts basis or contractual obligation. http://news.morningstar.com/classroom2/course.asp?docId=5458&page=3&CN=sample

28 CEG, *Debt transaction costs and PTRM timing benefits*, January 2019, p. 20.

Additionally, Chairmont advised that CEG's adjustment does not 'reflect the true cost of issuance, or that a benchmark efficient firm in the supply of regulated energy services bears these costs'.[29] It noted that underwriters (and not the issuers) bear any post issuance trade price difference and that the arrangement fee is set before bond issuance.[30]

3.4.8 PTRM timing benefits and indirect debt raising cost

The CEG report recommended that two new costs to be (both indirect debt raising costs) included in the debt raising allowance:

- Liquidity costs–to establish and maintain bank facilities to meet S&P's liquidity requirements to maintain an investment grade credit rating.
- Three months ahead financing – to compensate for S&P's requirement that businesses re-finance their debt 3 months ahead of the maturity date of their existing debt.

These costs total approximately 12 basis points per annum.[31] CEG's reasoning for proposing these costs was that the PTRM's timing benefits had fallen (from 1.8 per cent to 7–8 basis points) and no longer fully covered these costs.

We note that we previously considered and rejected these indirect costs on the basis that the PTRM's timing benefits already fully compensated for them.[32] We acknowledge CEG's submission that the PTRM's timing benefits have decreased due to a falling WACC. However, we are not satisfied that including either category of costs in the debt raising costs benchmark is necessary to compensate a service provider for the efficient costs of raising its debt. Our updated modelling continues to indicate that the PTRM's timing benefits fully compensates for CEG's proposed indirect costs. It is also not clear to us if, and to what extent, regulated energy network businesses incur these costs.

More detail on our assessment is in the sections below.

Previous considerations

We previously considered indirect debt raising costs in revenue determinations following the 2013 Rate of Return Guidelines. We were not satisfied that either category of costs were necessary to compensate a service provider for the efficient costs of raising its debt because:[33]

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29 Chairmont, *Debt Raising Costs*, 29 June 2019, p. 16.

30 Chairmont, *Debt Raising Costs*, 29 June 2019, p. 16.

31 CEG, *Debt transaction costs and PTRM timing benefits*, January 2019, p. 10.

32 AER, *Final decision SA Power Networks determination 2015–16 to 2019–20 Attachment 3–Rate of return*, October 2015, pp. 513–514.

33 AER, *Preliminary Decision, SA Power Networks distribution determination 2015-16 to 2019-20, Attachment 3 – Rate of return*, April 2015, p. 516.

- The ACG's 2002 report and modelling concluded that the PTRM's timing assumptions already provide a favourable treatment of 1.8 per cent for the timing of revenue compared to expenses, to the extent that these cost streams are necessary.[34] We noted that this treatment would be further enhanced by the additional ½ WACC capex adjustment[35] to recognise capex in the middle of each year. Therefore, there was no need for additional allowances to provide liquidity, or to compensate the service provider for the timing of its financing. This was because the PTRM implicitly provided a favourable allowance that exceeded these amounts.

These proposed allowances resulted in a more complex regulatory approach to estimate debt raising costs given the modelling and data requirements to estimate these two additional categories.

Assessment

In response to CEG's submission, we consider it important to first investigate if the PTRM's timing benefits changed over time using SA Power Networks as a case study.

The ACG model requires the following inputs to determine the size of any timing benefit provided by the PTRM:

- information from the PTRM
    - RAB
    - Opex
    - Capex
    - Depreciation
    - Pre-tax real WACC
- payment and revenue cycles.

We used information from SA Power Networks' proposed PTRM and requested information from SA Power Networks to cross check CEG's inputs. As part of this exercise, we have also updated the ACG model with the most material update incorporating the half-WACC adjustment to capex we implemented after 2002.

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34 Allen Consulting Group, *Working capital, Relevance for the assessment of reference tariffs, Report to the ACCC*, March 2002.

35 We apply the 1/2 WACC capex adjustment to address a timing difference between when capex is incurred and when it is modelled in the PTRM. Capex is assumed to be incurred evenly throughout the regulatory year and therefore a timing assumption is adopted that on average places capex half-way through the year. However, the PTRM calculates the return on capital based on the opening RAB for each regulatory year and capex is not added to the RAB until the end of the regulatory year in which the expenditure on the asset is incurred. The PTRM applies a half-real vanilla WACC to capex (capitalised and recovered over the life of the assets) to compensate for the six-month period before capex is included in the RAB.

Based on these inputs, our updated modelling indicates timing benefits of around 19 basis points per annum (bppa) which fully covers CEG's indirect costs of 12 basis points.

In addition, it is not clear if, and to what extent, regulated energy businesses incur these indirect costs:

- SA Power Networks' regulatory proposal did not provide evidence of incurring these indirect costs.
- CEG stated that a reason for indirect costs is to maintain an investment grade credit rating.[36] However, Chairmont
- advised that in the case of liquidity management costs 'rating agencies determine a rating by considering a range of factors, including management experience, sovereign risk, and so on'.[37] It is not clear that these indirect costs are necessary to maintain an investment grade rating.

CEG's modelling of timing benefits

We note that CEG made a number of adjustments to its version of the ACG model in modelling a PTRM timing benefits of 7–8 bppa. We generally disagree with these adjustments and our consideration is summarised in the table below.

Table 3.6 CEG adjustments to ACG model

Issues	Considerations
The value of timing benefits must exclude the cost of tax (12.45%) paid on those timing benefits.[38]	We note that costs including the proposed indirect costs are generally tax deductible and CEG has not provided contrary evidence for the indirect costs. Given CEG's proposed indirect costs does not account for the reduction in tax, we consider that a more like-for-like comparison means the PTRM timing benefits should also not be reduced by the cost of tax.
CEG submitted that SA Power Networks hold around $30m of inventory outside the RAB. This results in an additional estimated annual cost of $1.6m by applying a nominal vanilla WACC of 5.43%.[39]	We note that the NER and NGR specifies that the annual revenue requirement to be composed of forecast opex, tax and return on, and return off, capital. Given inventory is not included in the RAB, we do not consider it appropriate to provide compensation for this item. Nevertheless, we have estimated the PTRM timing benefits taking into account the cost of holding the inventory. To be consistent, we apply the same WACC as that used to estimate the timing benefits. We consider our estimate of 19 bppa is still sufficient to cover inventory-related cost of 3.2 bppa and CEG's proposed indirect costs of 12 bppa.

36 CEG, *Debt transaction costs and PTRM timing benefits*, January 2019, p. 10.
37 Chairmont, *Debt Raising Costs*, 29 June 2019, p. 17.
38 CEG, *Debt transaction costs and PTRM timing benefits*, January 2019, p. 36.
39 CEG, *Debt transaction costs and PTRM timing benefits*, January 2019, p. 36.

Issues	Considerations
CEG's timing benefit modelling used cash flow timing assumptions based on the advice from SA Power Networks. It considered some of ACG's timing assumptions are not consistent with the advice from SA Power Networks nor with the AER's benchmark assumptions applied to SA Power Networks.[40]	To cross-check and inform ourselves of the PTRM's timing benefits, we requested information from SA Power Networks relating to its cash flow cycles. We have used these updated cash flow information where appropriate in our updated ACG model.
ACG's framework implicitly assumes the service provider can borrow and lend at the same rate. In practice, a business will face a higher interest rate when borrowing than when it is lending, such that the favourable PTRM timing benefits is less than that implied from ACG's framework.[41]	We disagree with this view. The discount rate used to discount the cash flows for a project reflects the rate of return required by the shareholders and debtholders in order for them to fund the project. When discounting a project's cash flow, the same discount rate should be applied to discount both cash inflows and outflows, rather than using two different rates for cash inflows and outflows.

40 CEG, *Debt transaction costs and PTRM timing benefits*, January 2019, p. 36.

41 CEG, *Debt transaction costs and PTRM timing benefits*, January 2019, p. 37.

A Confidential Appendix (Averaging Period)