Electricity Market Advisory Services

Report for Energy Consumer Australia's Submission to the AER's 2026 Rate of Return Instrument Review

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The Authors

Greg Watkinson has a thorough understanding of the operation, design, and risks facing the energy sector. In his previous roles as CEO and Member of the Economic Regulation Authority, Greg was responsible for regulation of monopoly infrastructure in Western Australia, monitoring market participant behaviour, and reviewing the effectiveness of the wholesale electricity market. He has substantial experience in economic and financial modelling, particularly in the energy and water sectors, and in the financial analysis of regulated businesses. At the Economic Regulation Authority, Greg had oversight of the work program for the first two rate of return instruments introduced under the National Gas Law to Western Australia. Since leaving the Economic Regulation Authority, Greg has been involved in substantive reviews of rates of return for the regulated fibre, airport and energy sectors in New Zealand.

Simon Orme is an expert in economic regulation, risk assessment, and access pricing in various sectors and across multiple jurisdictions, including electricity and gas networks, retail energy, water, airports and other infrastructure. His regulatory expertise is recognised by his appointment by the WA government to the WA Energy Review Board and panel. Simon developed an innovative analysis for IEEFA comparing actual returns on equity achieved by monopoly networks (ex-post) compared with efficient returns in line with the prevailing RoRI. Simon has consulted to the AER, including leading an independent review of operating environmental factors for OPEX productivity benchmarks, the demand management incentive scheme, and providing research, technical and drafting support for the Consumer Reference Group in the first RoRI review.

Overview

The 2026 Rate of Return Instrument (RoRI) review is an opportunity for the Australian Energy Regulator (AER) to address settings that have led to higher than necessary electricity and reticulated gas prices. Our assessment of the issues for the Review is in response to the AER's 2026 RoRI Discussion Paper and the Eligible Experts' report.

This report provides our findings from our assessment of the systematic risk facing network service providers (NSPs), the proposal to form a weighted trailing average return on debt, and more generally on the settings that have affected electricity and reticulated gas prices.

Taken together, our analysis indicates there is an opportunity for the 2026 RoRI review to improve on decisions in previous RoRI that are resulting in network prices being significantly higher than necessary. **We estimate that annual network revenue (for aggregate electricity) would have been lower by around 6.4%, or $941 million, if the settings we propose had been in place for the last round of resets**.[1]

The rate of return is the most important factor determining network revenue and the network component of retail bills (it was 48% of network distribution revenue in 2025).[2] The RoRI review is being conducted against a background of rising network costs that are contributing to retail bill increases substantially exceeding the economy wide rate of inflation.[3]

In response to concern over affordability, and the inflationary impact of rising power bills, the Australian government has subsidised power bills by more than $6.8 billion over the two and a half years to the end of December 2025. Our analysis indicates the bill consequences of our recommended changes to the RoRI parameters would have been equivalent to around 35 per cent of Australian government subsidies.[4]

We recognise that the outcome of the 2026 RoRI review will not have an immediate impact on network tariffs, retail bills, and hence economy-wide inflation. Nevertheless, we suggest the AER has an obligation under the Revenue and Pricing principles to make substantial adjustments to the 2026 RoRI to restore an appropriate balance between suppliers and consumers, without affecting incentives to invest.

[1] Based on a reduction of 6.4% using the effect on Ausgrid distribution as representative of the effect on NSPs generally and total network distribution and transmission revenue of $14.6 billion, from AER State of the Energy Market 2025 , Figure 3.5.

[2] See AER State of the Energy Market reports for the relevant periods.

[3] See the discussion on the inflation impact of rising electricity prices and falling budget subsidies in the ABS CPI release for the September Quarter 2025.

[4] See detailed description of the Energy Bill Relief Fund (EBRF) at page 3.

The RoRI review is a complex topic that has been difficult for consumer groups to engage in and as a result has been heavily influenced by network providers.

Our analysis indicates the current rate of return settings are not consistent with:

- the section 181(4) requirement that "the AER must have regard to … the prevailing conditions in the market for equity funds… and… the prevailing conditions in the market for debt"; and
- "a return on capital should be provided to the network service provider commensurate with the regulatory and commercial risks involved in providing direct control network services".

The AER indicated at the public forum with the Eligible Experts that it is broadly comfortable with existing RoRI settings. We disagree with this assessment and consider the evidence in this report indicates why the AER's view cannot be sustained. Unfortunately, the Discussion Paper did not identify any matters relevant to ensuring that customers pay no more than necessary for a safe and reliable network service. The only substantive matter identified related to concerns raised by suppliers regarding the impact of the current RoRI on "lumpy" and uncertain capital expenditure profiles.

We recommend the AER broaden the scope of its review to explore all ways to reduce the impact NSPs have on electricity prices without compromising incentives to invest. This would also address the non-alignment between the AER's approach to the 2026 RoRI Review, on the one hand, and its concurrent review of all other components of the retail bill stack, on the other.[5]

As part of exploring this broader scope, the AER would need to ask the Eligible Experts to reconsider their findings in light of the main context of this review – the energy affordability problem – and to identify opportunities for addressing energy affordability without compromising incentives to invest.

The AER has formed its view of the systematic risk facing NSPs over many rate of return reviews involving extensive public consultation and expert review. The equity beta was set at 0.8 in 2009, reduced to 0.7 in 2013 and then reduced again to 0.6 in 2018.

[5] See AER, Default Market Offer 2026-27 Issues Paper (November 2025).

After an extensive review of existing settings and international energy utility firm data, **we have concluded that equity returns are too high and the equity beta should be reduced from 0.6 to 0.5 or below.**

Our review of the ways NSPs have been insulated from risk provides strong qualitative evidence that current allowed returns may be too high, relative to the returns required for a benchmark entity with a comparable exposure to systematic risk.

Our empirical analysis indicates that mean equity betas differ in a statistically meaningful way across countries and, in particular, between the Australian NSPs and international energy utilities.

We have reviewed the energy utilities that comprise a large international comparator set and, in Appendix D, provide our reasons for excluding the majority of these firms. Our assessment is that only international energy utilities providing monopoly network services are useful comparators and that proposals to use international energy utilities as NSP comparators cannot be sustained.

The main reasons for exclusion are that the international comparator set mainly comprises vertically integrated regulated energy utilities with risk profiles that diverge substantially from the risk profiles of Australian NSPs with statutory monopolies. This factor is acknowledged in the AER Discussion Paper. The risk profiles of the vertically integrated entities in the international comparator set are more akin to the major Australian price-regulated gentailers than to NSPs. For example, in the US, around a third of power and gas customers are in jurisdictions where statutory monopolies have been removed fully or partially.[6] Where suppliers retain a monopoly, their scope of business and associated energy trading and customer-related risk profiles are more like integrated Australian energy companies than NSPs.

The 2022 RoRI estimate relies on a regulatory judgment to include firms in the comparator set that do not hold statutory monopolies for most of their revenue (see Figure 10). However, the AER's network performance reporting indicates the **leverage of these firms is being maintained at levels significantly higher than the 60% benchmark, while at the same time the cost of debt has been significantly lower than the benchmark assumption**.[7] It is likely that the reason NSPs can sustainably increase their leverage above the benchmark level, without increasing debt financing costs, is because the actual equity beta is lower than the benchmark level.

[6] See US Energy Choice Overview: State-by-State Analysis - RESA USA

[7] The AER does not publish leverage data in its annual network performance reports, but these were provided to one of the present authors, on request in November 2023. The term "leverage" refers to the proportion of the regulated asset base (RAB) that is financed by debt.

For the RoRI decisions to be evidence-based, they must be capable of being cross checked (falsified) by actual (ex-post) data. Our review highlights the value of cross checks in complementing the use of forward-looking data.

We have reviewed the AER's decision to set the term of the risk-free rate for the return on equity at 10 years rather than 5 years and have concluded that it was not based on evidence that a 5-year term would compromise incentives to invest. **We therefore do not consider the 10-year term is consistent with a reasonable interpretation of the NPV=0 condition or the Revenue and Pricing Principles**.

We also consider there is merit in making a RAB adjustment at each reset to ensure the nominal return on equity throughout the regulatory period was equal to the nominal return forecast at the reset. This adjustment would benefit NSPs and consumers by removing the windfall gains and losses associated with compensating equity investors for inflation under the status quo. The AER's assumption in its 2020 inflation review that unexpected inflation can be passed through to consumers, because 'Newtork charges for consumers move in line with their incomes and wages,'[8] is not consistent with the evidence. Real wages have fallen 6.5% since 2014 and 16.5% since 2019.

On the weighted trailing average return on debt, we have reviewed the many new ways that governments and rule changes reduce risks to the timing and size of TNSP investment. The AER in its Discussion Paper does not explain why changes to the method for estimating debt costs in the RoRI are required on top of wider changes to date.

We have modified our EMAS NSP model so that we can examine the implications of a weighted trailing average for consumers. We provide a summary of the method in Appendix A.

If the proposed weighted trailing average is introduced, we see risk for consumers. The first problem is that it could result in higher prices. Our review has indicated that NSPs appear to incur less capital expenditure, and therefore borrow less, when interest rates are lower and vice versa. This means that a weighted trailing average would result in a higher return on debt, and therefore higher prices, than a uniform trailing average, all else equal. There should be a high hurdle, therefore, before it is approved.

A second problem was highlighted by the Eligible Experts, which is that **it is not fair to consumers that NSPs benefited when the trailing average portfolio return on debt** (**TAPRD) was trending down, compared to what would have happened if the return on debt had still been set at prevailing rates, and consumers will not have the opportunity to claw these benefits back as the TAPRD stabilises and starts to trend up**. NSPs were able to adopt debt

[8] AER, Final Position, Regulatory treatment of inflation (December 2020), page 67.

financing strategies that reduced their costs relative to the benchmark and are now supporting a change as they find it more difficult to beat the benchmark. If the AER decides to adopt a weighted TAPRD, consumers should be compensated for foregoing the benefits that they otherwise would have received from a continuing uniform TAPRD. We consider the most appropriate method for making this adjustment is through a one-off adjustment to NSP RABs.

Our review has shown that variations between forecast and actual compensation for the cost of debt (that is, the amount underlying allowable revenue) substantially exceed the relatively small variations in compensation that would result from implementing a weighted TAPRD rather than a uniform TAPRD. For example, Ausgrid's (total realised and unrealised) compensation for the cost of debt in 2023-24 was over $400 million higher than assumed at the reset, whereas the difference in its compensation from being on a weighted TAPRD compared to a uniform TAPRD would have been only $4 million in that year.

The variation between the trailing average return on debt and the return on debt underlying allowable revenue would be avoided if the AER assumed NSPs actually implement a trailing average return on debt. This would involve **changing the specification of the real return on debt so that it is based on the applicable inflation rate for the year rather than the forecast inflation rate**.

The AER appears reluctant to include matters to do with inflation in the scope of this review because it considers inflation is not relevant to the RoRI. We disagree, for the following reasons:

- The AER may make an instrument [RoRI] only if satisfied the instrument will, or is most likely to, contribute to the achievement of the national electricity objective to the greatest degree (NEL18I(3)). This indicates a possible positive obligation for the AER to adopt a more expansive definition of the scope of the RoRI than in its 2018 and 2022 reviews, including with respect to the specification of the real return on debt.
- The return on assets earned by NSPs is affected by the specification of the RoRI, Post Tax Revenue Model, annual revenue adjustments, the RAB Roll Forward Model and various other parts of the regulatory framework. It is not appropriate to consider the return on assets as a matter for the RoRI alone. The Revenue and Pricing Principles relate to pricing and return outcomes, not just to ex-ante forecasts.
- The return on debt is currently specified in the RoRI in nominal terms. It is open to the AER to specify the return on debt in real terms in the RoRI to be consistent with the real rate of return framework that underlies the AER's regulatory approach.

- Interest rates incorporate an expectation of inflation. It is not appropriate to consider the return on debt without also considering how NSPs are compensated for the risk associated with inflation.

- Another regulator, Ofgem, has included matters to do with the effect inflation has on the cost of debt in its equivalent to a RoRI review, and has made a change that has a similar effect to what we are recommending.

- The proposed options for implementing a weighted TAPRD have a similar scope, relative to the RoRI parameters, as our proposal to change the way the real return on debt is specified. These options include changes to the PTRM as part of annual updates, or to the RAB Roll Forward Model at price resets.

- Many of the reasons the AER provided in the 2020 review of inflation in support of the status quo[9] have been tested during the recent inflationary experience and cannot be sustained. In particular, the assumption that wages will keep up with inflation and changes in network prices is not supported by the evidence; the view that risks associated with inflation are best managed by consumers and NSPs is not reasonable given the parties have few if any ways of managing this risk (and given the rules could be changed to address this risk); and the assumption that the forecast real return will be achieved is not consistent with how inflation is accounted for in the regulatory settings.

We therefore recommend the AER include the specification of the real return on debt as a matter that is within the scope of the 2026 RoRI review.

We respond to the AER's specific questions in Appendix F.

[9] AER, Final Position, Regulatory treatment of inflation (December 2020), page 67.

1 Introduction

EMAS has been engaged to assist Energy Consumers Australia (ECA) with its submission to the Australian Energy Regulator's (AER) 2026 Rate of Return Instrument (RoRI) review. This report is provided for attaching to ECA's submission to the AER.

In general, the substantive matters for this review, from a consumer perspective, are:

- Ensuring the return on debt appropriately accounts for the costs incurred by the benchmark NSP; and
- Ensuring the return on equity appropriately accounts for the systematic risk of NSPs.

2 Implications of the RoRI review for consumers

2.1 Context for the 2026 RoRI review

Monopoly network charges are the single largest component in retail electricity bills, representing 33% to 48% of total retail electricity bills.[10] The return on capital calculated under the RoRI – the estimated cost of financing electricity and gas network infrastructure – is typically the single largest single cost building block determining total regulated revenue and monopoly network tariffs.

Rising power bills contributed significantly to economy-wide inflation in the year to the end of October 2025 exceeding the Reserve Bank of Australia's (RBA) upper target range of 3 per cent. The Australian Bureau of Statistics Consumer Price Report for the 12 months to October 2025 noted that the 9% increase in electricity prices, driven by annual price reviews and a reduction in government rebates, was a significant factor in the overall inflation outcome for the period.[11]

RBA concerns over rising inflation contributed to its 9 December decision to leave the cash rate unchanged. In explaining this decision, the RBA Governor explicitly referenced the fact that '[electricity] *Rebates temporarily lower headline inflation, and as they roll off the headline inflation will move higher*.'[12]

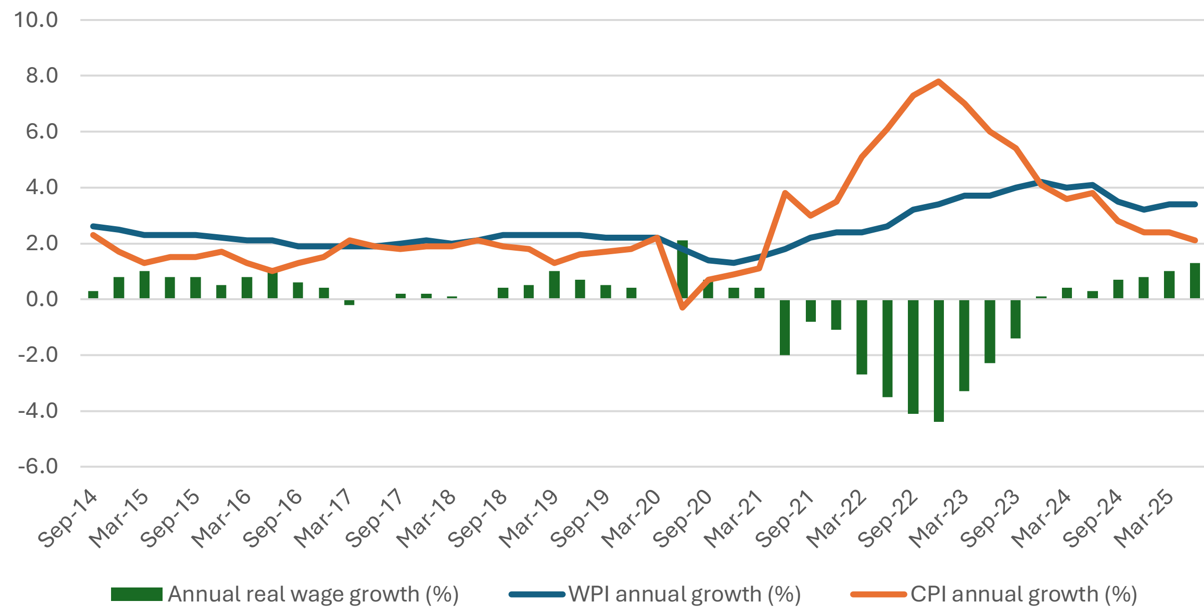
ABS CPI and wages data show that wage growth has not kept pace with inflation in the 10 years through to September 2025, as shown in Figure 1. Real wages have fallen 6.5% since 2014 and 16.5% since 2019.

[10] AER, State of the energy market 2025– Electricity networks (2025), page 82.

[11] See October 2025 CPI report, Australian Bureau of Statistics, as at November 2025, available here.

[12] See paragraph 2 of the explanatory statement by the RBA Governor.

Figure 1. Real wage growth 2014-2025



In response to the decline in power affordability, the Australian and some State governments allocated significant budget subsidies to reduce the impact of rising power bills. The Energy Bill Relief Fund (EBRF) provided rebates in a manner intended to reduce the impact of rising retail power bills on economy wide inflation.

Budget allocations over the 2.5 years from FY2024 to FY2026 (end of 2025) are expected to total $6.8 billion.[13] This is summarised in Table 1.

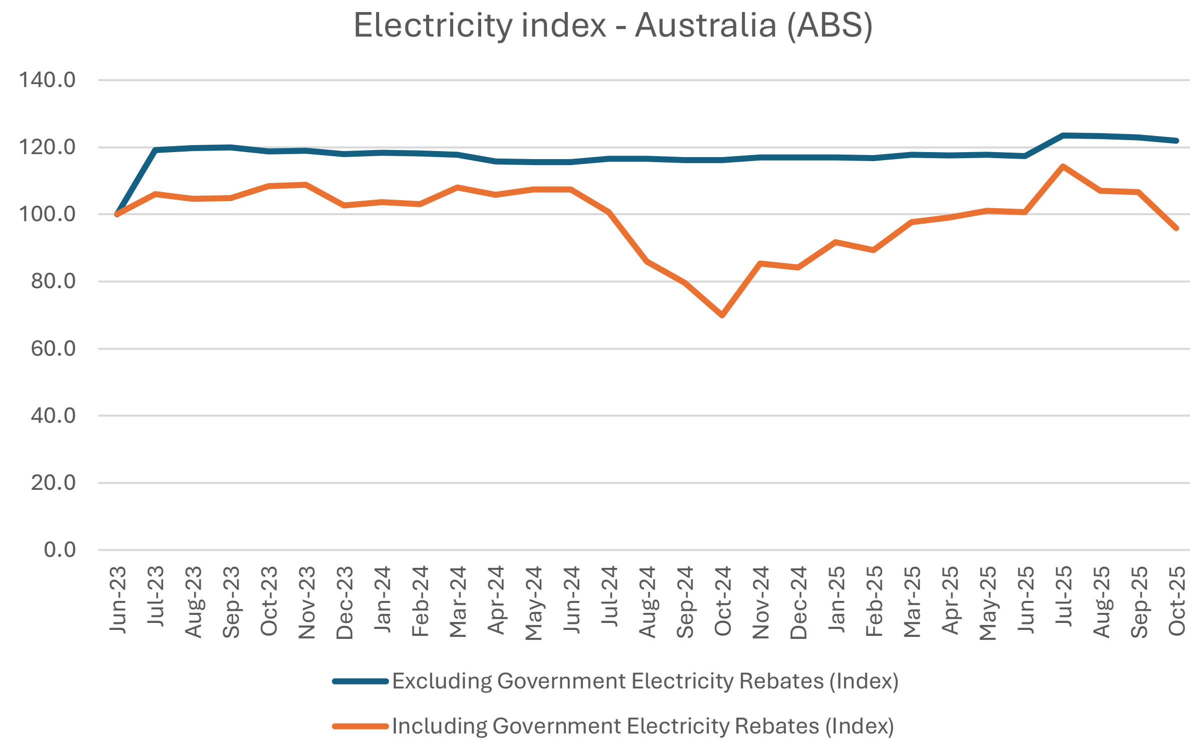
Table 1. EBRF federal budget allocation - national

	$ billion
2024	1.5
2025	3.5
2026 (end of 2025)	1.8
Total	6.8

The EBRF payments are made directly to retailers rather than customers. This results in a decrease in retail bills and hence recorded CPI. ABS' assessment of the impact of the EBRF on the contribution of retail electricity prices to economy wide inflation is reproduced in Figure 2.

[13] The total ERBF is allocated between the NEM and WA on a per customer basis and in the final quarter of calendar 2025 has also been extended to households in WA (thereby increasing the gap between the two indices. This suggests the allocation to the NEM excluding FY2026 is more than 90% of the total above and should be discounted by less than 10%.

Figure 2. ABS electricity index with and without government electricity rebates



Source: Electricity Index, Australia, ABS

The dark blue line in this figure highlights the impact of electricity retail price increases effective from July 2025. While these increases were moderated by an extension of rebates (orange line), the rebates are due to expire entirely at the end of December 2025. Following an announcement by the Government that it will not extend the EBRF into calendar 2026[14], from January 2026 consumer electricity prices will revert to the dark blue line in Figure 2.

2.2 Contrast between 2026 RoRI Review and 2025 reforms to the Default Market Offer

There is a strong contrast between the AER's conduct of the 2026 DMO review, on the one hand, and its approach to the 2026 RoRI, on the other. Monopoly network charges are outside the scope of the 2025 reforms to the DMO.

In June 2025, the Australian government initiated a review of electricity retail regulation, in the form of the Default Market Offer (DMO) and associated retail reference price.[15] The AER's RoRI Review Discussion Paper is dated August 2025, well after the review of the DMO had been announced and work begun.

[14] See ABC News Government will not extend energy bill relief (8 December 2025).

[15] The DMO applies only in NSW, SE Queensland and SA. Retail price regulation is undertaken under separate but similar arrangements in Victoria, regional Queensland, ACT and Tasmania.

The Discussion Paper does not identity any matters relevant to ensuring that customers pay no more than necessary for a safe and reliable network service. The main substantive matter identified relates to concerns raised by suppliers regarding the impact of the current RoRI on "lumpy" and uncertain capital expenditure profiles. Extensive evidence that outcomes under the RoRI are substantially exceeding efficient financing costs, as identified elsewhere in this report, was not raised in the Discussion Paper.

The first stage of the DMO review was completed in November 2025.[16] Among other things, changes to the relevant regulations were recommended. These include a set of proposed new mandatory requirements that the AER must follow including that the DMO is based on 'the efficient costs of serving small customers' and [to] 'cap the prices payable by those customers.' This reflects a proposed new DMO objective to:

> *'…protect households and small businesses on standing offers and in embedded networks by providing a fair, trusted and reasonably priced electricity option that reflects the costs of supplying customers with an essential service.'*

The introduction of this proposed new DMO objective was in response to recognition that the regulations do not contain any consumer protection objectives or principles and instead require the AER to have regard to the principle that retailers should make a reasonable profit (or return on capital).[17]

In *Default market offer 2026-27 Issues Paper*, dated November 2025, the AER sets out its view of the implications of the proposed regulatory changes for its 2026 DMO decision and for a new DMO Guideline for following DMO decisions. The AER states it will systematically review the entire DMO cost stack, excluding network costs, for opportunities to ensure that DMO prices conform to the DMO objective. This includes, among other things removal of the 'competition allowance', adjusting load profiles, moving from the 75th to the 50th percentile estimate of the wholesale electricity cost and potentially also removing the volatility allowance.[18]

Both the Government and the AER are actively seeking to identity opportunities to reduce retail bills and costs arising from the non-monopoly parts of the supply chain. So far, a similar approach has not been evident in the AER's framing and scoping of the 2026 RoRI review.

[16] See Department of Climate Change, Energy, Environment and Water, *Review Outcomes; 2025 reforms of the Default Market Offer* (November 2025).

[17] Page 20, Ibid.

[18] Ibid.

2.3 Opportunity to restore balance between consumers and suppliers

The analysis in this report has identified several opportunities to restore the balance between consumers and suppliers in the 2026 RoRI. Total financing costs can be reduced significantly, without compromising supplier incentives to invest.

We have calculated that, if the recommendations in this report had been applied to the last set of NSP resets, sector wide electricity network revenue would have been lower by around 6.4% per year, or by about $941 million, as shown in Table 2.

Table 2. Benefit to electricity consumers had our recommendations been in place at the last round of resets[19]

	%	$ million
Equity beta of 0.5	-2.8	416
NSP revenue based on TAPRD	-1.9	278
Return on equity term of 5 years[20]	-0.9	134
Removal of windfall gains and losses for the return on equity[21]	-0.6	118
Combined total	-6.4	941

The $941m effect on electricity NSP revenue per year would have been approximately 34.6% of the EBRF allocation when calculated over the 2.5 years of the EBRF program. The inflationary and budget impacts of rising power bills would have been moderated.

We recognise that the outcome of the 2026 RoRI review will not have an immediate impact on network tariffs, retail bills, and hence economy-wide inflation. Nevertheless, we suggest the AER has an obligation under the Revenue and Pricing principles to make substantial adjustments to the 2026 RoRI to restore an appropriate balance between supplier and consumer interests. This requires extending the scope of the 2026 RoRI Review to include the following matters:

- The term of the risk-free rate for the return on equity.
- The extent equity investors are over-compensated because of the level of the equity beta and evidence that NSPs are sustaining higher than benchmark gearing levels.

[19] This table is based on our analysis of the effect of the recommendation on Ausgrid distribution's revenue in 2024-25. It assumes Ausgrid's revenue for the remainder of the regulatory period increases in line with the expected inflation rate. The percentage change for each recommendation has been calculated on a stand-alone basis, whereas the total assumes all recommendations had been adopted and due to interaction effects is not the sum of the stand-alone calculations.

[20] Assumes a 0.5 percentage point difference between the average yield of 5-year and 10-year government bonds, and an offsetting adjustment to the MRP which is moderated by the effect of the equity beta.

[21] Assumes a 5-year term for the return on equity. Under the alternative scenario of a 10-year term for the return on equity and an annual update to the risk-free rate, the benefit to consumers would have been $87 million.

- The specification of the real return on debt.
- The potential for windfall gains or losses associated with the treatment of inflation for equity investors.

These matters are addressed in detail in the remainder of this report.

3 The weighted trailing average portfolio return on debt

The AER's Discussion Paper identifies, as a priority issue for review, the existing method of calculating the TAPRD. The concern is that the equal weighting of historical interest rates can result in a misalignment of the prevailing interest rate with the requirement for additional debt financing. In particular, we understand that the reason the AER is considering a weighted trailing average is because NSPs are concerned that they won't be compensated for the risks associated with investments required for the transition to renewable energy.

We recommend the AER:

- verify that there is a residual financing problem requiring a change to a weighted trailing average, given recent policy, budget and regulatory initiatives support investment during the transition to renewable energy;
- investigate the risk that a weighted trailing average would result in higher prices compared to a uniform trailing average. It is likely that when interest rates are low, capex is also low as economic uncertainty leads to additional caution when NSPs commit to new projects. If NSP's borrow less when interest rates are low and borrow more when interest rates are high, a weighted trailing average will result in higher prices, all else being equal.
- assume NSPs actually implement a trailing average, which requires a change to the definition of the real return on debt (but otherwise would not involve any more extensive changes than required to implement a weighted trailing average). This change would recognise that the impact of the current specification of the real return on debt on NSP revenue is substantially greater than the impact of switching from a uniform to a weighted TAPRD.
- if it decides to adopt a weighted TAPRD, compensate consumers for foregoing the benefits that they otherwise would have received from continuing with the uniform TAPRD. We consider the most appropriate method for making this adjustment is through a one-off adjustment to NSP RABs.

3.1 Is there a residual financing problem requiring changes to the TAPRD?

While there is an extensive discussion of options for addressing the perceived financing problem of not having a weighted TAPRD in the RoRI Discussion Paper, there is no discussion of the wider context and whether a series of policy, budget and regulatory initiatives have left a significant residual financing problem requiring changes to the RoRI. This means that, on the evidence provided so far, the Discussion Paper has not demonstrated there is a case for changing the current method for weighting the TAPRD.

A comprehensive set of policy, budget and regulatory initiatives is now in place to support adequate and timely investment for priority transmission projects in the Integrated System Plan (ISP) and other regulated capital expenditure. This is in response to recognition of the challenges arising from investment constraints under monopoly network regulation. Key policy, budget and regulatory initiatives include the following.

- The creation of the Rewiring the Nation Corporation and allocation by the Australian government of $20 billion capital in 2022 to fund concessional network financing managed by the Clean Energy Finance Corporation (CEFC).
- Previous provision of *ad hoc* government underwriting of major NSP capital expenditure commitments, including for 'early works', in advance of regulatory approval from the AER under the Regulatory Investment Test.[22]
- In 2024, a rule change took effect that increases cost recovery certainty for TNSPs and provides an incentive to undertake more pre-construction investment earlier in the economic assessment process.[23] Under the new rule, a TNSP can seek cost recovery for early works without having completed a RIT-T.
- The introduction of a new financeability rule in 2024. Under the new rule, if a TNSP has a financeability issue, the final rule requires the AER to bring forward the TNSP's cash flows related to an actionable ISP project through a combination of one or more of as incurred depreciation, varying the depreciation profile of assets, and revenue smoothing (adjusting X factors) within a regulatory control period. This, in turn, will improve a TNSP's financial metrics and consequently, its ability to efficiently raise finance, facilitating timely investment in and delivery of actionable ISP projects.[24]

Taken together, it is unclear whether there are any gaps in these arrangements that require further action in the form of change to the RoRI treatment of the weighting of the TAPRD. On a forward-looking basis, the AER may already have sufficient discretion to address any financeability challenges arising from large interannual variations in debt financing necessary to support increases in capital expenditure.

Where concessional (CEFC) or government underwritten financing is applied, the required return on capital for new investment is reduced relative to the RoRI benchmark. This is because government underwriting or concessional financing avoids or reduces a need for any risk

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[22] See for example Transgrid, Federal underwrite of $385 million to accelerate the energy transition and secure critical supplies (2 March 2023).

[23] See AEMC, Bringing early works forward to improve transmission planning (September 2024).

[24] See AEMC, Accommodating financeability in the regulatory framework and especially clause 6A.6.3A regarding the Financeability adjustment following an Actionable ISP project trigger event.

premium above the relevant concessional or 'risk-free' rate. This means that, for example, any reduction in historical returns before the new measures above took effect, due to capital expenditure underwritten by government but not yet approved by the AER, does not imply that the regulated entity was financially disadvantaged from that investment. While returns were reduced, so was the marginal risk requiring compensation.

NSPs have significant degrees of freedom to access debt finance at globally competitive prices and to avoid refinancing during periods and in markets where debt financing prices might be significantly higher than long term trends. As a result, NSPs have extensive opportunities to outperform the relatively unsophisticated financing arrangements assumed for the benchmark entity.

3.2 General method of calculating a weighted average

In order to examine the implications of a weighted TAPRD on consumers we have modified our model of NSP revenue (the EMAS NSP Model) that we use to evaluate regulatory settings.

The EMAS NSP Model incorporates the three steps associated with calculating an NSP's revenue allowance. The first part is the approximation of the PTRM, which is used to calculate an NSP's forecast revenue and X factors. The second part is the annual update to the return on debt, which involves the recalculation of X factors. The third part is the adjustment to allowable revenue for the applicable inflation rate and X factor for the relevant year.

For this RoRI review we have populated the EMAS NSP Model with data from Ausgrid's distribution business and have checked to ensure that it largely replicates the revenue allowance calculated for each year, which it does.

We have modified the model to incorporate a weighted TAPRD (without a transition back to a uniform trailing average for individual tranches of debt as we agree with the Eligible Experts that this would be overly complex and not necessary to achieve efficient investment incentives). Our method of calculating a weighted TAPRD is explained in detail in Appendix A. In general, it involves:

- supplementing the annual update process by identifying the NSP's asset base and rolling it forward using actual capex;[25]
- calculating the opening and closing debt values that are associated with the rolled-forward asset base;
- calculating the annual borrowing requirement as the difference between the closing debt value and the debt value that is consistent with the benchmark leverage position;

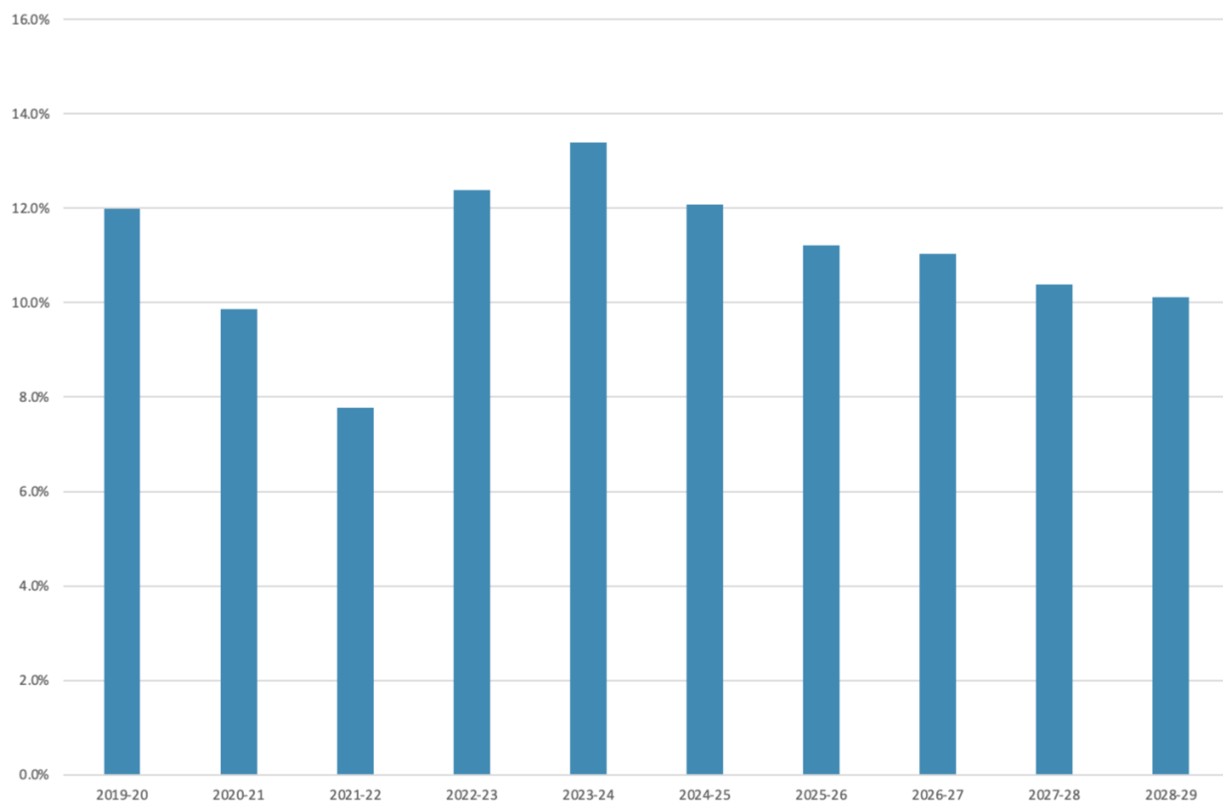
[25] A true-up would be required at the reset if the capex incurred was not deemed compliant with the rules.

- using the annual borrowing requirements to calculate the weighted TAPRD;[26]
- applying the weighted TAPRD to calculate the revised X factors; and
- applying the revised X factors and applicable inflation rates to calculate the annual revenue allowances.

We consider that this method is a relatively straightforward way of adopting a weighted TAPRD (and consistent with comments made by the Eligible Experts that the transition to a uniform trailing average is overly complex). The only additional information needed is the annual capex data from the NSP. It matches the prevailing interest rate to the amount of additional borrowing required by the NSP (assuming it maintains the benchmark leverage position).

We have illustrated the application of the weighted TAPRD by applying it to Ausgrid's distribution business. If the weighted TAPRD had been applied at Ausgrid's 2020 reset, their additional borrowing as a proportion of opening debt would have varied from the uniform rate of 10% by over 2 percentage points in some years, as shown in Figure 3.

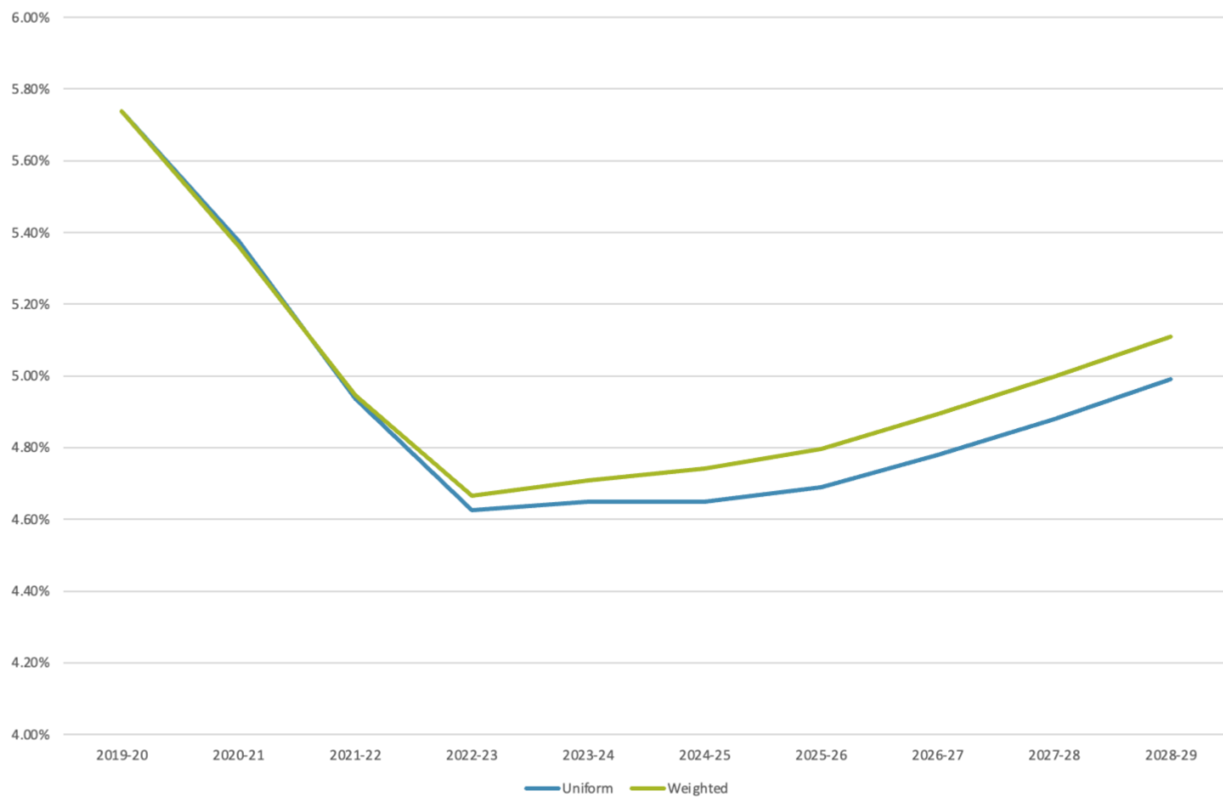
Figure 3. Additional borrowing as a percentage of opening debt, Ausgrid distribution



[26] The existing debt at the time the new method is implemented has interest rates that vary each year as each tranche of historical debt is repaid (that is, each year the interest rate associated with the oldest tranche of debt is excluded from the calculation of the return on existing debt).

Figure 4 shows that the weighted TAPRD would have tracked above the existing TAPRD from 2022-23 had it been applied to Ausgrid's distribution business for the last two resets, and it would likely result in a higher return on debt for the remainder of the current regulatory period. The reason for this is that Ausgrid's capex was low in 2021-22 when the prevailing interest rate was low (2.12%) and high in 2023-24 when the prevailing interest rate was high (6.77%).

Figure 4. Current versus weighted portfolio trailing average return on debt, Ausgrid distribution



3.3 Why does the AER not assume that NSP's actually implement a trailing average?

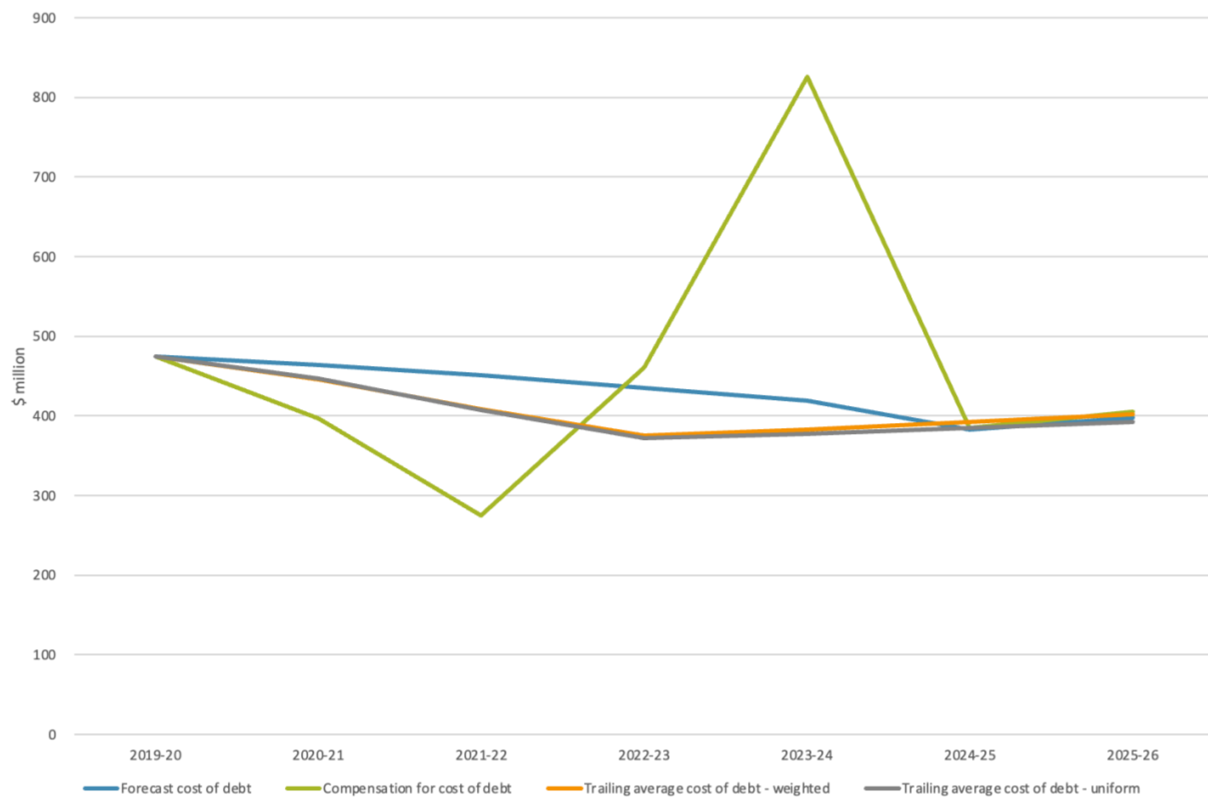
Given that the AER has made the weighted trailing average a focus of this review, the natural question is why not assume that the NSPs actually adopt a trailing average portfolio of debt? The decision not to do so is a deliberate design choice of the AER's, as they have said "there is no requirement for us to set allowances that match a particular financing practice such as a nominal return on debt"[27].

However, this design choice has substantial implications for NSPs and consumers. Figure 5 shows the large difference between the cost of debt that Ausgrid was expected to incur over

[27] AER, Final Position. Regulatory treatment of inflation (December 2020)

the last seven years (blue line) and the total realised and unrealised compensation for the cost of debt that underlies its return on assets (green line).

Figure 5. Cost of debt for Ausgrid Distribution: actual compensation compared to actual and forecast cost



This highlights that variations between forecast (blue line) and actual compensation for the cost of debt (green line) substantially exceed the relatively small variation between the uniform (grey line) and weighted (orange line) TAPRD. Note that the compensation to NSPs for the cost of debt associated with unexpected inflation is generally realised in revenue following the RAB adjustment at the next reset rather than immediately.[28]

The actual compensation for the cost of debt results from the way the AER specifies the nominal return on debt that underlies an NSP's revenue allowance:

$$nominal\ return\ on\ debt = (1 + real\ return\ on\ debt) \times (1 + applicable\ inflation\ rate) - 1$$

[28] An NSP's nominal return on equity for any year includes realised and unrealised components. The unrealised component is based on the incremental annual difference between the NSP's RAB and actual asset base. When inflation increases the cost of debt, compensation for the inflated cost is embedded in the RAB and is not realised as revenue until future regulatory periods.

where:

$$real\ return\ on\ debt = \frac{(1 + TAPRD)}{(1 + forecast\ inflation\ rate)} - 1$$

With this specification, the AER achieves ex-post NPV=0. However, it requires the compensation for the cost of debt to vary substantially. The large increase in 2023-24 shown in Figure 5 is the result of the following values:

$$TAPRD = 4.65\%$$

$$forecast\ inflation\ rate = 2.42\%$$

$$real\ return\ on\ debt = 2.17\%$$

$$applicable\ inflation\ rate = 7.83\%$$

$$nominal\ return\ on\ debt = 10.17\%$$

The AER could align revenue with the assumption that the NSP implements a TAPRD by reinterpreting its real approach to the cost of capital. Specifically, it could specify the real return on debt as follows.

$$real\ return\ on\ debt = \frac{(1 + TAPRD)}{(1 + applicable\ inflation\ rate)} - 1$$

Under this formulation the inflation rate used to convert the TAPRD to a real return on debt is the same as the inflation rate used to convert the real return on debt to a nominal return on debt. Therefore,

$$nominal\ return\ on\ debt = TAPRD$$

We have verified that this alternative specification of the real return on debt achieves ex-post NPV=0.

We consider the best and simplest way to deal with this issue (i.e. the way with minimal changes to existing regulatory settings) would be to continue with the current method of calculating X factors and revenue within a regulatory period and then make a true-up to the RAB at the reset. This would ensure NSPs are compensated for the benchmark trailing average return on debt, no more or no less.

For example, if a true-up were applied to Ausgrid's RAB at its last reset, the RAB would have been lower by $427 million and its allowable revenue would have been lower by 1.9% from 2024-25. Similar reductions would have occurred for other NSPs.

3.4 Is the specification of the real return on debt within the scope of the RoRI review?

In our view, reasons for addressing the specification of the real return on debt in the RoRI review include:

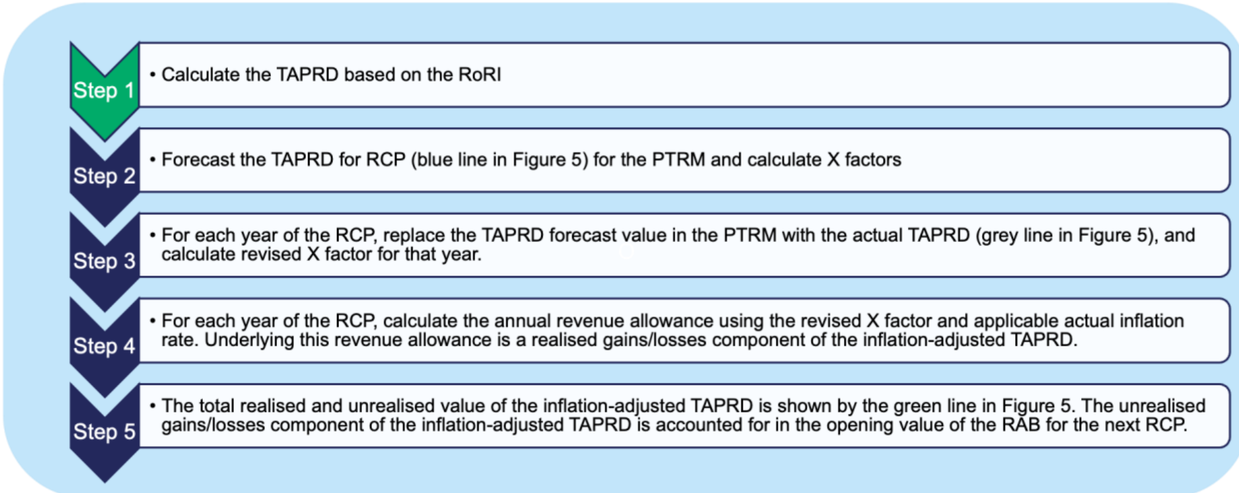
- The AER may make an instrument [RoRI] only if satisfied the instrument will, or is most likely to, contribute to the achievement of the national electricity objective to the greatest degree (NEL18I(3). (emphasis added). This indicates a possible positive obligation for the AER to adopt a more expansive definition of the scope of the RoRI than in its 2018 and 2022 reviews.
- The AER is obliged by the NEL to have regard to the revenue and pricing principles in its RoRI decisions. The revenue and pricing principles relate to pricing and return on equity outcomes, and associated efficiency impacts, not merely to ex-ante forecast returns without reference to outcomes and impacts. The AER approach in the two previous RORI reviews appears to 'read down' the requirements of the revenue and pricing principles.[29]

In NER Cl6.5.2 the formula refers to the return on capital for "the" [i.e. a single] regulatory year ("at"), not to a set of regulatory years over a five-year or longer period.

In our view, the impact of the annual return on debt adjustment is already within the scope of the 2026 RoRI review, as defined in the Discussion Paper. The steps associated with the calculation of the compensation for the cost of debt is shown in Figure 6 below.

[29] Noting we are not qualified to offer legal advice on the interpretation of the NEL.

Figure 6. The steps for calculating NSP compensation for the return on debt



In our view, Section 5.2 of the Discussion Paper and Appendix A do not make the potential expansion of the scope of the RoRI sufficiently clear.[30] While the current RoRI instrument is limited to Step 1 in Figure 6, the Discussion Paper includes an extensive canvassing of alternatives to the current approach to setting the return on debt. The AER contemplates changing Step 3 and/or Step 5 for the impact of the actual capex profile on the allowed return on debt, relative to the allowed return on debt as calculated under Steps 1 and 2.[31] Figure 5 shows the substantial difference between the forecast return on debt in Step 2 and the full compensation for the return on debt in Step 5.

The inclusion of Steps 3 and 5 above in the scope of the Discussion Paper is intended to address potential mismatches between allowed revenue for debt financing cost and actual debt financing costs, but only where this arises from substantial inter-annual variations in capital expenditure associated with the transition to renewable energy, especially for transmission companies.[32] This can result in debt raising and hence debt costs varying substantially from year to year relative to the costs calculated using a uniform or simple TAPRD.

As shown in Figure 5, the impact of the specification of the real return on debt on NSP revenue is substantially greater than the impact of switching from a uniform to a weighted TAPRD. The objective of minimising mismatches between allowed and actual debt financing costs, by a move to a weighted TAPRD applies more strongly to the specification of the real return on debt.

[30] Similarly, the discussion of the what the AER describes as the impact of the 'inflation rate variation' on the actual regulated return on equity in section 5.3.2 of the 2024 Electricity and gas networks performance report, does not transparently explain how this impact arises across the five steps depicted in Figure 6.

[31] See S5.2 of AER, Rate of return instrument: review Discussion Paper (August 2025)

[32] See discussion above suggesting AER may already have sufficient discretion to address this problem under rule changes in 2024.

Identified options to address any mismatches include changes to the PTRM and to the Roll Forward Model.

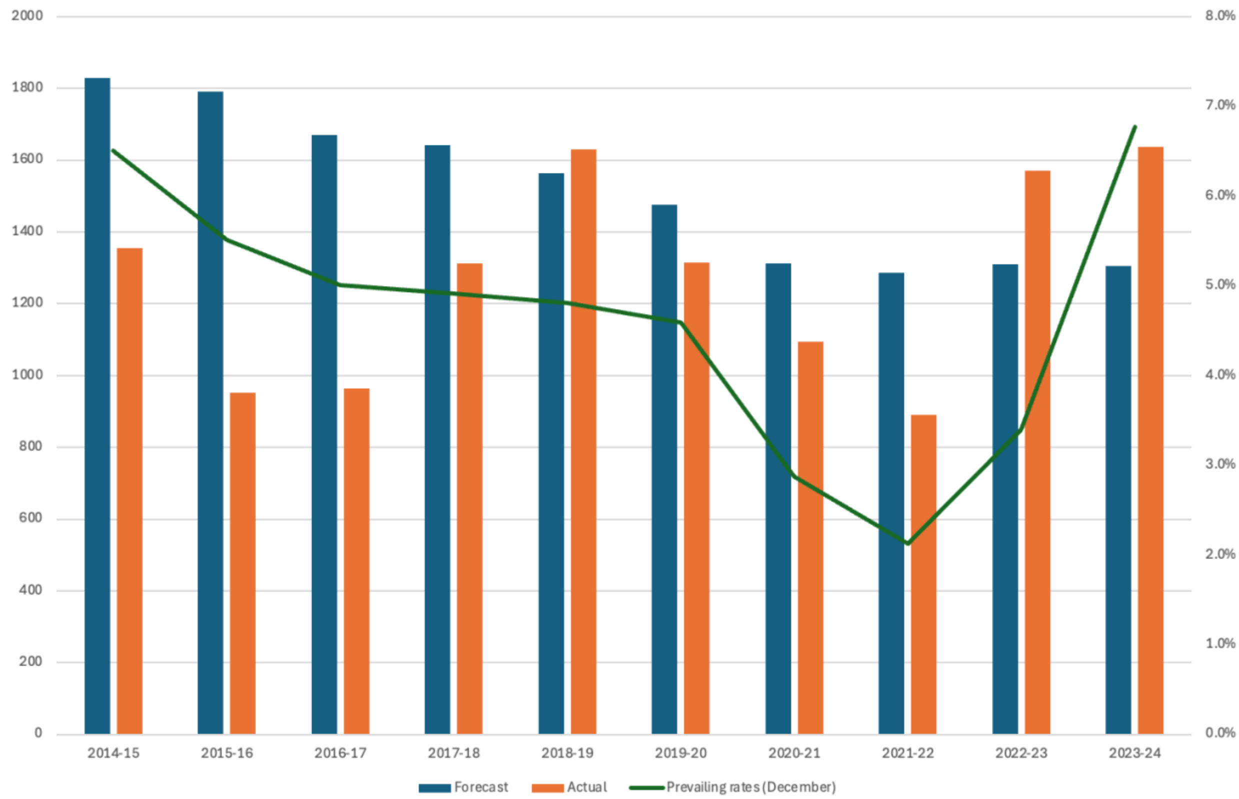
The AER has so far not explained why the steps in Figure 6 are within scope for addressing any problems arising from inter-annual variations between forecast and actual volume of debt raised, but out of scope for differences between actual TAPRD and compensation for TAPRD (the blue and orange lines in Figure 5). We acknowledge that both are outside the existing RoRI scope, but we can see no logical way steps 3 and 5 can be excluded for one highly impactful matter and included for another far less impactful matter.

3.5 Could a weighted trailing average lead to an increase in prices?

We are concerned that a move to a weighted trailing average could lead to an increase in prices. The analysis in Appendix B indicates the recent increase in nominal capex across the NSPs, likely due to a combination of inflation and the transition to renewable energy, has coincided with an increase in interest rates.

For example, Figure 7 shows the historical capex (forecast and actual) for NSPs with access arrangements commencing in 2019-20 and compares it to prevailing interest rates. Forecast capex is generally more evenly spread over the regulatory period, whereas actual capex varies substantially.

Figure 7. Forecast and actual nominal capex, and nominal interest rates for NSPs with access arrangements commencing in 2019-20[33]



Our analysis indicates that had a weighted trailing average been in place over the last set of access arrangements, prices would have been higher than under a uniform trailing average. It is likely that when interest rates are low, capex is also generally low as economic uncertainty leads to additional caution as NSPs commit to new projects. We consider the AER should investigate this possibility further, as if this is a general finding then a weighted trailing average would be expected, all else equal, to result in higher prices. To justify the change, the AER would need to conclude that the incentive gains from a weighted trailing average would more than offset the detriment to consumers from higher prices.

A related point is that if the AER decides to move to a weighted trailing average, it should ignore actual historical borrowings and instead assume that capex has been financed under a uniform trailing average. To do otherwise would add substantial pressure to prices.

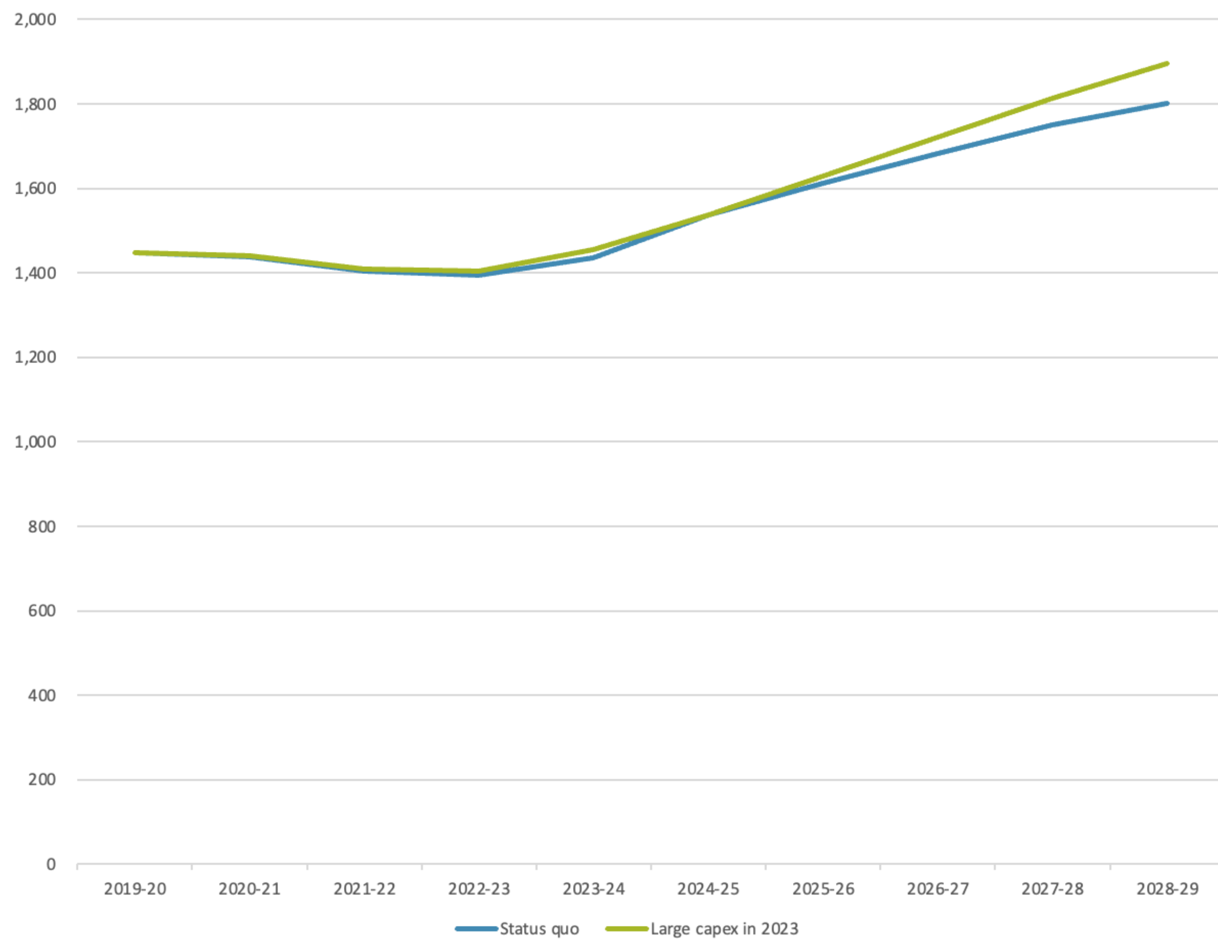
We have also considered what could happen to prices if there were a large annual increase in the weighted TAPRD which coincided with a spike in inflation.

[33] This group includes Ausgrid, Endeavour Energy and Essential Energy.

We have modelled a scenario using Ausgrid's distribution data to see what would have happened to allowable revenue if Ausgrid had required a large amount of additional borrowing when the applicable inflation rate was 7.8% in 2024. We have assumed capex was $1,000 million compared to the forecast of $477 million for that year. For this year the additional borrowing as a proportion of total debt would have been 13.4% rather than 10% under the status quo.

Figure 8 shows that Ausgrid's revenue allowance would have been higher in 2024 (by 1.3%) but most of the increase in revenue would have been smoothed over the following regulatory period.

Figure 8. Scenario of large capex coinciding with high inflation for 2024, Ausgrid distribution



On the basis of this scenario, the concern about a high inflation event occurring with a large increase in capex may not be overly concerning from a consumer perspective.

3.6 Comment on the Eligible Experts' findings

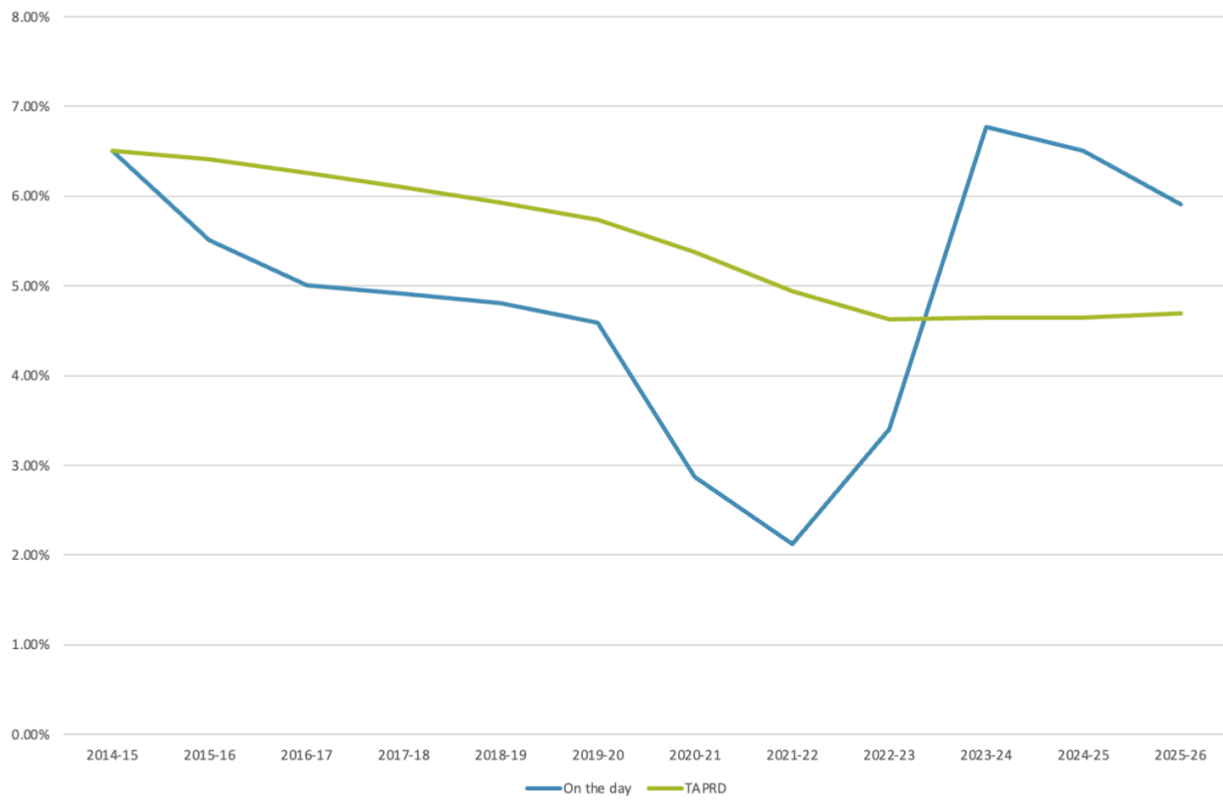
Our main takeaways from the Eligible Experts' review of the options for a weighted TAPRD are:

- The TAPRD has fundamental problems:
    - it was introduced as interest rates were declining and the AER's RoRE reporting indicates it has been consistently beaten by NSPs;
    - it is at risk of being gamed: that is, it was introduced when interest rates were declining and may be changed when interest rates are increasing. Consumers are therefore unlikely to claw back the benefits gained by NSPs in the past if the method is changed to a weighted TAPRD;
    - it is not reasonable to assume a uniform portfolio of debt (or even a weighted portfolio) is an efficient financing strategy;
    - it compromises investments when the additional borrowing requirement is greater than 10% of the stock of debt; and
    - it is not a discount rate and should not be used in present value calculations.
- If the weighted TAPRD is to be introduced, it should be applied to all NSPs rather than only those that exceed a certain threshold.
- Some form of true-up should be applied to correct for capex forecasting error.
- The transition from a weighted TAPRD for particular tranches of debt back to a uniform TAPRD is complex and unnecessary.

We concur that it is not fair to consumers that NSPs benefited when the TAPRD was trending down, compared to what would have happened if the return on debt had still been set at prevailing rates, and consumers will not have the opportunity to claw these benefits back as the TAPRD stabilises and starts to trend up.

The problem is illustrated in Figure 9 which shows the long period when the on-the-day interest rate was lower than the TAPRD, and the recent reversal which has been associated with a call for a change to the method.

Figure 9. Return on debt for Ausgrid under the TAPRD compared to what it would have been if the on-the-day approach had continued



We have calculated that Ausgrid has benefited by $1,025 million between 2014-15 and 2022-23 from the move to the TAPRD and will have been worse off by $492 million between 2023-24 and 2025-26. The net gain to Ausgrid has been around $500 million. Similar net benefits have been achieved by other NSPs.

In our view the TAPRD method should only be changed to a weighted TAPRD if consumers are compensated for the change through a one-off adjustment to NSP RABs. This adjustment would depend on the net benefit received by the NSP at the time the weighted TAPRD is introduced.

A general comment on the views of the Eligible Experts is that they appear to have insufficient clarity about the very large effect the specification of the real return on debt has on NSP returns, or the fact the UK regulator Ofgem has responded to this problem, whereas the AER has not.[34] This suggests that the connection between the actual compensation for the return

[34] In a July 2024 decision, Ofgem stated that it would no longer index the notionally geared regulatory asset value to outturn inflation. This completely removes the inflation effect from the cost of debt. This change is due to take place under the RIIO-3 price control, which will run from 1 April 2026. See Ofgem, RIIO-3 Sector Specific Methodology Decision – Finance Annex (18 July 2024), paragraph 1.11.

on debt and the specification of debt in the regulatory framework is not transparent, even to experts.

In particular, we note the discussion between the experts on whether NSPs have outperformed the benchmark cost of debt appears to have been limited by the fact the Discussion Paper does not explain how the TAPRD is implemented, per Figure 6. One expert points to the AER's RoRE analysis as evidence for outperformance, but does not appear to appreciate the connection between outperformance in relation to the implementation of the TAPRD arising from 'Inflation rate variation' in the AER's RoRE analysis. Another expert points to the AER's review during the 2022 RoRI of the Energy Infrastructure Credit Spread Index against the benchmark credit spread associated with the trailing average allowance, as evidence outperformance relating to debt financing is immaterial.[35]

We consider the AER's RoRE analysis provides the basis for indicating outperformance as it encompasses all of the factors that influence an NSP's compensation for the cost of debt (as described in Figure 6). This reporting shows the outperformance is both highly material, especially due to the 'inflation rate variation', and persistent.

We also note the issue raised by Partington that the discount rate used in present value calculations should not be the same as the WACC based on the TAPRD. This issue should be reviewed by the AER, with a consequential change so that the opportunity cost of capital, based on the on-the-day cost of debt, is used when making true-up adjustments.

[35] See discussion across paragraphs 500-505 of the Eligible Experts' Joint Report.

4 Systematic risk

From our review of NSP exposure to systematic risk we have found:

- NSP investors are extensively insulated from risk;
- the comparator set analysis indicates the equity beta for NSPs should be no greater than 0.5; and
- cross check analysis using AER network performance data indicates that NSPs are managing to sustainably lower their costs by applying a leverage position that is higher than the benchmark level.

Our recommendation is that the AER should revise down the equity beta set in the RoRI to a value no greater than 0.5.

We have also reviewed the AER's decision to set the term of the risk-free rate for the return on equity at 10 years rather than 5 years and have concluded that it was not based on evidence that a 5-year term would compromise incentives to invest. We therefore do not consider the 10-year term is consistent with a reasonable interpretation of the NPV=0 condition or the Revenue and Pricing Principles.

We also consider there is merit in making a RAB adjustment at each reset to ensure the nominal return on equity throughout the regulatory period was equal to the nominal return forecast at the reset. This adjustment would benefit NSPs and consumers by removing the windfall gains and losses associated with the return on equity under the status quo.

4.1 Systematic risk exposure of Australian NSPs

The AER has formed its view of the systematic risk facing NSPs over many rate of return reviews involving extensive public consultation and expert review. The equity beta was set at 0.8 in 2009, reduced to 0.7 in 2013 and then reduced again to 0.6 in 2018.

We have concerns about the returns being earned by NSPs, as reported by the AER[36], as we consider these returns are not commensurate with the risks faced by NSPs.

Before the development of the RoRI, in its cost of capital decisions, the AER set out in detail the various ways NSPs operating under the NEL and NGL are protected from systematic risk.[37] For example, unlike in some jurisdictions, and before the development of the current national

[36] AER, 2024 Electricity and Gas Networks Performance Report (September 2024)

[37] See for example 'Table 3-3: Key clauses in the rules that mitigate systematic risk,' 3-27, AER, Attachment 3 – Rate of return; AusNet services distribution determination final decision 2016-20 (May 2016).

electricity rules, electricity networks were subject to asset stranding risk where assets could be optimised during resets.[38]

Asset stranding risk was transferred to consumers from around 2006, with the move to the roll-forward method for setting the opening RAB for each regulatory control period, replacing earlier methods that included optimisation. This meant that networks in Queensland, NSW and Tasmania did not experience asset optimisation, as recommended by the ACCC in its 2018 Retail electricity Pricing Inquiry Final Report. This is despite substantial excess capital investment and consequential stranded assets.[39]

Capital expenditure risks are increasingly evident through the energy transition. Notable examples include the commissioning delays and capital cost increases of Snowy 2.0 pumped hydro and the NSW side of a new SA-NSW transmission interconnector being developed by Transgrid (Project EnergyConnect).[40] These problems resulted in the failure of Engineering, Procurement and Construction (EPC) company, Clough.[41]

Snowy does not have a statutory monopoly and therefore needs to recover the cost of commissioning delays and increased capital costs via its competitive energy trading activities. The impact on its financing cost is likely to be assisted by its full government ownership.

By contrast, Transgrid's statutory monopoly, and other aspects of the regulatory regime, mean that Transgrid bears no increase in its costs and margins because of the delay in Project EnergyConnect commissioning. Increases in wholesale energy prices due to the delay do not affect Transgrid. It can be expected that Transgrid will apply to the AER to reopen its current regulatory determination so that it can increase the capital expenditure permitted to be recovered from regulated tariffs, in line with the increase in capital cost.

Depending on decisions to be taken by the AER with regard to Transgrid's reopening proposal, Transgrid could face some penalties under the capital expenditure sharing scheme (CESS). Alternatively, it is possible that the AER could deem some portion of the increased capital expenditure is inconsistent with the relevant rules regarding capital expenditure prudency and efficiency. However, any such penalties, or reduction in asset value transferred to the RAB, are likely to be dwarfed against the increase in dollar regulated returns over the up to 50-year life of the increased asset values.

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[38] See for example, page 6 of IPART, Electricity Prices (March 1996).

[39] A portion of the excess investment can be attributed to changes to reliability standards in both Queensland and NSW, meaning excess capital investment and asset stranding cannot be attributed entirely to the transfer of asset stranding risk to consumers.

[40] See ABC news, $1.5 billion blowout for Australia's largest energy transmission project (1 March 2025).

[41] See Sydney Morning Herald, Snowy Hydro, other energy projects face cost blow outs after Clough collapse (6 December 2022).

Table 3 shows the impact of the NER on the economy wide (systematic) drivers of beta. A detailed breakdown by specific NER is provided in Appendix E.

Table 3. Impact of NER on equity beta

Beta determinant	NER impact
Market competition	NSPs are statutory monopolies, unlike typical price-regulated energy utilities in Australia and internationally
Revenue volatility	NSPs are immune from changes in value or volume of electricity and gas transported. Revenue/price smoothing and tariff reform reduce seasonal and inter-annual revenue and profitability variability.
Customer/counterparty credit risk	All customer and counterparty risks are held by energy retailers and generators
Cost of goods sold	No exposure to changes in prices of underlying gas and electricity commodities
Operating expenditure	Inflation adjustments to revenue reduce this risk to NSPs, especially where labour cost changes are lower than inflation.
Capital expenditure risk	NSPs do not incur the cost of delays or increases in the capital cost of new infrastructure, notably transmission assets. By contrast, delays in commissioning generation (or transmission) can substantially affect gentailer competition and profits
Asset stranding risk	Transferred from NSPs to consumers with move to roll-forward method for setting RAB in place of asset valuation methods using optimisation
Inflation	NSPs bear inflation risk but this is mitigated by annual resets that assume all NSP cost changes correlate with CPI.
Regulation	Stable regulatory framework for NSPs since Better Regulation reforms from 2014 and NSP success in litigation against the AER.[42] The introduction of the RoRI from 2018 has not adversely affected NSP returns. By contrast, Australian energy utilities have seen retail margins and asset values affected due to the reintroduction of retail price regulation in 2019, and climate change related policy and regulation (e.g. NSW Electricity Infrastructure Roadmap in 2020).

[42] See Sydney Morning Herald, Households facing 'price spike' as regulator loses key court case (24 May 2017).

For the gas market, demand is typically substitutable, meaning that gas NSPs may have a higher exposure to systematic risk than electricity NSPs. The AER has on occasion approved proposals for accelerated depreciation from gas NSPs[43], and the AEMC is currently considering proposed changes to the relevant gas rules on accelerated depreciation and gas exit fees.[44]

In our view, the high level of protection from systematic risk is a key reason historical equity beta estimates for Australian listed NSPs were lower than identified international comparators. This suggests a high level of caution is required when using international comparators and they should only be considered if they are also operating under a regulatory regime that shifts systematic risk from suppliers to the extent this occurs in the NEM.

It also suggests continued reliance on Australian equity estimates pre-dating 2006 may over-state systematic risk from 2006. Aspects of the structural difference between actual and allowed RoRE over the 10-year period 2014- 2023 suggest the current equity benchmark estimate does not require any upward adjustment.

Figure 10 summarises the AER's benchmark comparator set beta estimates from the 2018 RoRI review relative to the 2022 RoRI equity beta decision (0.6) and AER's estimates of the percentage of revenue subject to network regulation.[45]

[43] See for example recent AER decisions approving accelerated depreciation for Jemena (NSW) and Australia Gas Networks.

[44] See Gas Networks in Transition | AEMC

[45] See Figure 14, AER, Rate of return instrument, explanatory statement (December 2018). Equity beta estimates for each benchmark entity are not presented in the equivalent document for the 2022 RoRI review. The estimates for most entities did not change between 2018 and 2022 because the entities were no longer listed on the ASX. The exceptions are SKI and AusNet.

Figure 10. AER benchmark comparator beta estimates

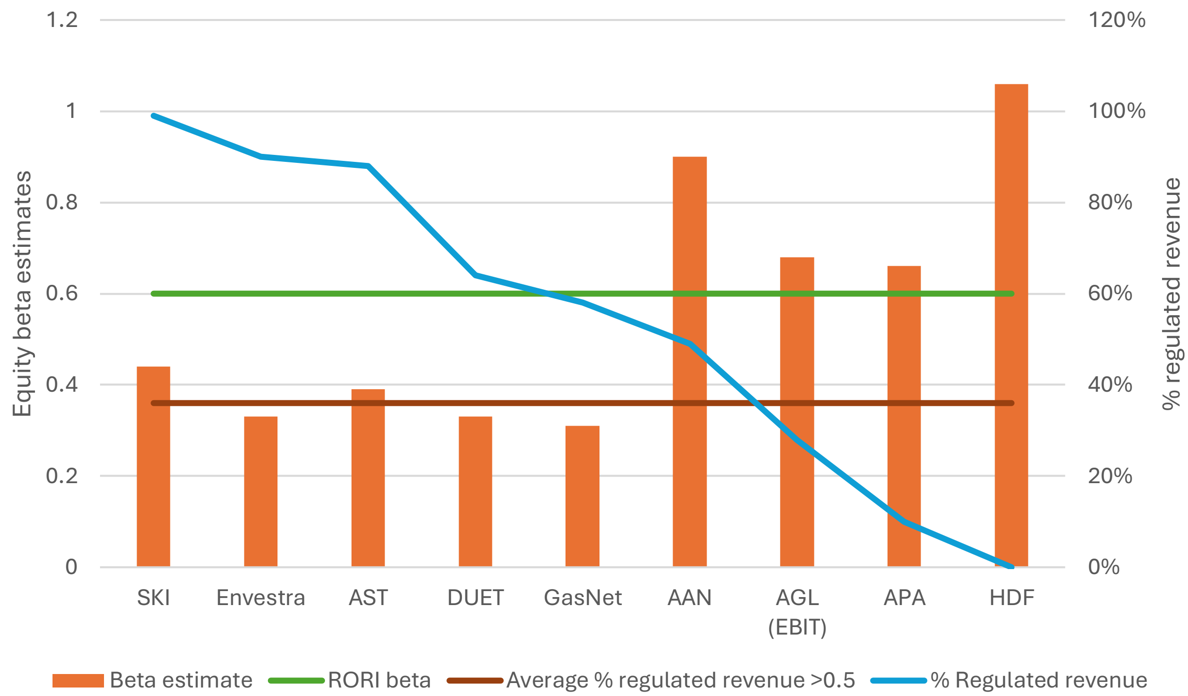

Figure 10 indicates the current RoRI equity beta is influenced by beta estimates for comparators that do not have the level of protection from systematic risk provided to NSPs. Excluding the comparators where regulated monopoly revenue is less than 50 per cent of revenue, the average equity beta for the five remaining entities is less than 0.4.

Related to this assessment, AER analysis of RoRE outcomes indicates that NSPs have been able to achieve both lower debt financing costs and higher leverage compared with the benchmark entity.[46] The reduction in equity financing from 40% to closer to 35% has so far not resulted in a debt financing penalty and indeed debt financing costs are lower than for the benchmark entity.[47]

Appendix E details the impact of specific NER on NSP exposure to systematic (economy wide) risk. This is from an AER created table included in a 2016 AER rate of return decision, updated for any changes to the rules.[48]

[46] AER, 2024 Electricity and Gas Networks Performance Report (September 2024), Figure 5-5 Detailed contributions to real RoRE – electricity NSPs and gas DNSPs - 2023, page 80. Similar outcomes are reported by the AER over the entire period 2014-2023.

[47] A possible related factor is the credit rating in the RoRI.

[48] See Table 3-3: Key clauses in the rules that mitigate systematic risk,' 3-27, AER, Attachment 3 – Rate of return; AusNet services distribution determination final decision 2016-20, (May 2016).

4.2 Issues with forming a set of comparator firms

The AER's Discussion Paper considers the issue of having only one listed firm in their comparator set and of having data from the delisted firms that are out of date.

In considering this international information we have applied the following decision framework:

- What international firms should be considered for inclusion in the comparator set?
- Would it matter if a broader set of international comparators were used?
- What method should be used to account for differences in leverage between firms?
- Does the resulting equity beta/leverage combination need to be adjusted for application to Australia?

4.3 Identifying a list of relevant comparator firms

When other regulators have sought international evidence to support their analysis of systematic risk, they have generally chosen firms in countries that have similar types of market economies, institutional and legal arrangements and regulatory settings. For example:

- The Commerce Commission in New Zealand has considered information from Australia, USA and the UK[49]
- The Economic Regulation Authority in Western Australia has considered information from USA, Canada and the UK.[50]
- Ofgem in the UK has considered information from Spain and Italy[51]

The Commerce Commission has used a sample of international energy firms to directly calculate their values of equity beta and leverage while the ERA has used a sample of international firms as a cross-check for their choice of equity beta and leverage. Ofgem decided to form its comparator set using relevant firms from Spain and Italy.

There are situations where regulators have chosen to use firms from countries that would not otherwise be considered similar to Australia. For example, the Commerce Commission used a broader sample of international firms in its comparator set when it first established the equity beta for regulated fibre services in New Zealand.[52] However, this is the exception rather than the norm in energy regulation.

[49] See for example Commerce Commission, Cost of Capital Topic Paper (13 December 2023), Attachment E.

[50] See for example Economic Regulation Authority, Explanatory statement for the 2022 final gas rate of return instrument (16 December 2022), Appendix 6.

[51] See for example Ofgem, RIIO-3 Draft Determinations - Finance Annex (26 August 2025).

[52] Commerce Commission, Fibre input methodologies Main final decisions – reasons paper (13 October 2020).

We note that it is possible to form a broader international data set by using information such as from Bloomberg. We recommend against doing so, for the same reason other regulators have generally decided not to do so, because these firms may not be relevant comparators. While from a statistical perspective, the inclusion of additional firms will increase the confidence in the mean estimate, if those firms are not relevant comparators this greater statistical accuracy has little economic usefulness.

Our starting point for this review is to take advantage of the decisions already made by similar regulators to compile an initial list of international energy firms. We have provided in Appendix C the firms that have been referenced by the Commerce Commission, ERA and Ofgem. These firms have survived a shortlisting process by these other regulators and are therefore suitable for consideration.

We have reviewed the firms in the international comparator set and provide our reasons for excluding individual firms in Appendix D. Our assessment is that very few international energy utilities are useful comparators and that proposals to use international vertically integrated energy utilities as NSP comparators cannot be sustained.

The main reasons for exclusion are that proposed comparator firms are vertically integrated regulated energy utilities whose risk profiles diverge substantially from the risk profiles for Australian NSPs with statutory monopolies. This factor is acknowledged in the AER Discussion Paper. The risk profiles of the vertically integrated entities in suggested comparator sets are more akin to the major Australian gentailers than to NSPs. For example, in the US, around a third of power and gas customers are in jurisdictions where statutory monopolies have been removed fully or partially.[53] Where suppliers retain a monopoly, their scope of business and associated risk profiles may be more like integrated Australian energy companies than NSPs, for reasons explained below.

A key driver of the disaggregation of the previously vertically integrated Australian energy utilities was a view that the risk profiles of the competitive and monopoly parts of the energy supply chain varied substantially and therefore financing costs and regulation would be more efficient and effective under structural separation.[54] Alongside structural separation policy decisions, for example the separation of transmission from generation, market driven industry restructuring also occurred. A notable example is that AGL separated its network assets (now APA group) from its energy trading and customer assets (AGL Energy).

[53] See Retail Energy Supply Association USA, US Energy Choice Overview, State by State Analysis.

[54] One of the authors of this report was a Principal Advisor in NZ and NSW Treasuries in the 1990s/early 2000s advising governments on the cost or capital and the separation of distribution and retail businesses, and generation and transmission businesses.

Any proposed reference to international firms with much higher earnings volatility than Australian NSPs can be expected to result in a substantial over-estimation of the earnings volatility of NSPs.

For example, vertically integrated energy firms are subject to energy trading, generation plant operating, infrastructure bottlenecks, final demand, customer credit and competition-related risks. All these risks tend to be pro-cyclical – variations in commodity prices, energy demand and bad debt and infrastructure bottlenecks are related to economic cycles.

This can result in substantial pricing and volume mismatches between energy purchase and customer supply commitments. For example, as seen in 2022 in the NEM, following the increase in global energy prices as a result of the Russian invasion of Ukraine, some NEM generators were short of fuel (gas and coal), and some were exposed to very high spot and forward market prices which could not be immediately recovered by way of increased retail prices. This led to at least one retailer becoming insolvent. Infrastructure bottlenecks are also more likely during periods of high economic growth and increased demand. For example, generators can face delays in procuring new generation capacity during periods of high demand growth.[55]

During economic downturns, economy wide energy demand is likely to be significantly lower than long term trends. This can result in energy trading losses as a result of both out of the money forward energy contracts and excessive contracted volumes relative to demand. This can significantly affect profits and shareholder returns. In addition, an increased share of revenue may become unrecoverable by a rise in business failures. Similarly, working capital requirements may increase due to increases in average payment delay.

By contrast, NSPs do not engage in energy trading, ownership and operation of energy generation assets contrasts, and do not bear financial risks from variations in final energy demand and payments over an economic cycle. Instead, the business model for NSPs is infrastructure tolling where revenues need only be sufficient to recover the fixed and variable costs of owning (including financing) and operating this infrastructure.

Even in competitive markets, infrastructure tolling revenues can be independent from changes in the value of the commodities using the infrastructure. However, revenues may nevertheless be affected by changes in volumes.

[55] See for example Institute for Energy Economics and Financial Analysis, Global gas turbine shortages set to increase delays and costs for gas-to-power projects in Vietnam and the Philippines (7 October 2025).

In the case of NSPs, variations in the volume of energy using the tolled infrastructure does not result in reduced revenues. If tolled volumes decrease, regulated unit prices are increased. NSPs are also protected from counterparty business failure and bad debtor risks.

As a result of higher systematic risk exposures, vertically integrated energy firms are likely to have substantially more variability in earnings compared with NSPs. Sources of systematic variability can include changes in demand, changes in wholesale commodity prices, the need to hedge against plant outages, transmission commissioning delays or outages,[56] the need to manage changes in bad debt and counterparty credit risk, and other variables.

In many US jurisdictions, while final distribution ("retail") prices are subject to performance-based regulation (PBR), customers can choose alternative suppliers.[57] In most cases, statutory monopolies are limited to a relatively small portion of business activities compared with Australian NSPs. Investor disclosures note that most investor-owned utilities (IOUs) are subject to extensive competition from other IOUs.

For some firms, a significant share of total revenue is not subject to PBR regulation and is fully competitive. Some IOUs undertake a wide range of activities including upstream exploration and production, operation of seaborne energy transportation and energy storage facilities, and extensive international investments. The form of regulation is usually cost of service rather than incentive-based regulation. A large-scale analysis of regulated energy utility financial performance in the United States tentatively finds that realised returns are falling relative to authorised returns and that full cost-recovery is declining due to an increase in utility investment and a flattening of revenue.[58]

Following our review of the international comparator set, we have concluded that the most suitable international comparator firms are:

- Vector, which is the largest electricity distributor in New Zealand and also owns the North Island gas transmission system;
- National Grid, which owns electricity transmission and gas distribution in the UK; and
- Hydro One, which owns electricity transmission and distribution in Canada.

Based on our analysis, we consider that these firms are the only international firms that should be included in the comparator set.

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[56] For example, reported impact of transmission constraints on profitability of Snowy Hydro in its annual report.

[57] See for example, Retail Energy Supply Association, Energy by State.

[58] See Yozwiak, M, *Calculating the realized investment returns of U.S. electric utilities*, (December 2023).

In our view, Australian firms Origin Energy, AGL Energy and APA are not valid comparators for NSPs because they do not hold monopolies, or their monopolies are a relatively small proportion of their earnings (APA). These firms may have risk profiles similar to those for integrated energy utilities in the US.

Origin has a much higher exposure to international commodity price cycles via its ownership of upstream gas and LNG liquefaction assets. When considered on a like for like basis, we expect that NSPs have substantially lower exposures to systematic risk than Origin. Firms with equity betas that are similar to integrated ASX energy firms, including APA, should therefore be excluded from the comparator set.

4.4 Would it matter if a broader set of international comparators were used?

We have tested whether we have been overly restrictive in our choice of comparator firms by considering whether using a broader set of international firms would make a statistically significant difference.[59]

The standard method for considering statistical significance is to identify whether the mean of a particular parameter (equity beta, asset beta or leverage) differs in a meaningful way between two groups.[60] P-values are often used to indicate statistical significance, by attempting to identify whether the difference in the means of two groups is sufficiently large for it to be unlikely to be caused by chance.

However, we consider that p-value tests should be used with caution for this exercise. Our understanding of the literature on the use of p-values is that they are not well-suited in this exercise because the groups are small and uneven, the beta estimates have high variance, the variances differ and the data include outliers.[61] Our concern is that the use of p-values might fail to detect real differences between groups. We also have strong prior knowledge that market, scope of business, regulation and institutional settings differ across pure play monopoly and regulated energy firms subject to varying levels of competition, which means that the use of a no-difference null hypothesis, as used when calculating p-values, is not a credible starting point.

[59] Note that we have not updated the beta and leverage data that have been published previously in support of decisions by economic regulators. We provide the source of the data we use in our analysis in Appendix C.

[60] We have used raw equity betas for this analysis as they are the observed data from regression analyses, whereas asset betas are derived using values of leverage.

[61] For a discussion, see Kruschke, J. K. Bayesian estimation supersedes the t test. Journal of Experimental Psychology: General, 142(2), (2013) 573-603.

Instead, we use a Bayesian two-group model which is designed for the statistical analysis of small uneven samples.[62] This model informs decision-making on the basis of probabilities rather than a discrete decision based on whether the p-value is less than 0.05.[63]

The Bayesian model estimates the most likely difference in the means between our pure-play set of 6 firms and the remaining 59 firms in the sample is -0.13 and that there is an approximately 91% probability that the difference in equity betas between the pure-play and other group exceeds an absolute value of 0.05 (the threshold difference in mean equity betas that we have defined as meaningful, although we note the AER has varied the beta in the past by 0.1).

The model also estimates, based on 4,000 simulations, that if one firm is selected at random from each group, the pure-play firm would have a lower equity beta about 71% of the time, so the pure-play firm is likely lower on average.[64]

We have concluded that the differences in the pure-play versus other equity betas are sufficiently large to be considered material. We are therefore comfortable with distinguishing the pure-play firms from other firms.

We are also concerned that regulatory and institutional arrangements may result in systematic risk differing across countries and that we may be biasing our analysis if we do not account for this.

The data in the broad comparator set indicates the risk of investing in energy firms appears to differ across countries. Table 4 is ordered from the country with the lowest WACC (Australia at 5.86%) to the highest (Canada at 7.69%).

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[62] We have formed the Bayesian model using the software package R based on information in Kruschke, J. K. *Bayesian estimation supersedes the t test*. Journal of Experimental Psychology: General. (2013).

[63] The Bayesian model is initiated by setting starting ranges (priors) for each group's true average beta and for how much firms vary around that average. The model then combines those priors with the actual data using a likelihood function that fits this context (a Student-t model that accounts for outliers and lets each group have its own variance). The model blends the two to produce a posterior: a whole distribution of plausible values for each group's average and for the difference between them. Practically, the computer simulates thousands of draws from this posterior using a modern sampler. Each draw is one coherent possibility consistent with the data and the priors. When all the draws are put together the model produces a full distribution: its centre is the best estimate, its width indicates uncertainty, and the share of draws where the gap exceeds the threshold is the probability the difference is material.

[64] We have also applied the Welch t-test which allows for the groups to be different sizes and have different variance. The average raw equity beta is 0.50 for the pure-play firms and 0.69 for the other firms, which is a gap of -0.19. The Welch test's 95% range for the true gap ranges from -0.29 to -0.08. The p-value of 0.002 indicates the null hypothesis that there is no difference between the two groups can be rejected.

Table 4. WACCs by country[65]

	Australia	NZ	Spain	US	Italy	UK	Canada
Number of firms	4	1	2	44	3	3	8
Nominal risk-free rate	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%
Cost of debt margin	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%
Nominal pre-tax cost of debt	*4.65%*	*4.65%*	*4.65%*	*4.65%*	*4.65%*	*4.65%*	*4.65%*
Market risk premium	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%
Asset beta	0.23	0.28	0.34	0.37	0.41	0.51	0.53
Equity beta	0.49	0.50	0.58	0.62	0.77	0.80	0.98
Post-tax nominal return on equity	*7.22%*	*7.29%*	*7.76%*	*8.01%*	*8.99%*	*9.13%*	*10.28%*
Proportion of equity funding	47%	56%	59%	60%	53%	64%	54%
Proportion of debt funding	53%	44%	41%	40%	47%	36%	46%
Corporate tax rate	30%	30%	30%	30%	30%	30%	30%
Nominal vanilla WACC	***5.86%***	***6.13%***	***6.49%***	***6.67%***	***6.95%***	***7.52%***	***7.69%***

We are interested in testing whether the difference in equity betas between Australia and other countries is statistically significant. However, as we have already established that pure-play energy firms are likely to have lower equity betas than other energy firms, and the Australian firms in our set are largely pure-play, we cannot simply compare the Australian firms to say the USA firms.

Instead, we can compare the 3 Australian firms in our comparator set with the 3 international pure-play firms (which are from the UK, Canada and New Zealand).

The Bayesian model estimates the most likely difference in the means between the pure-play and other group is -0.14 and that there is an approximately 90% probability that the difference in equity betas between the Australian and International pure-play firms exceeds an absolute value of 0.05. Based on 4,000 simulated future draws from the fitted model, there is a 21% probability that a new observation from the Australian group would have a higher equity beta than a new observation from the other pure-play group. These results indicate it is reasonable to conclude there is a meaningful difference between the two groups.[66]

[65] The WACCs in this table have been calculated using a zero debt beta and average leverage of the comparator set.

[66] We have also calculated the p-values for the Australia pure-play and other pure-play comparison using the Welch t-test. The average raw equity beta is 0.43 for Australia and 0.57 for the other group. The test's 95% range for the true gap ranges from -0.31 to 0.01, which is wide and includes zero and means the data are consistent with Australia being lower, higher, or the same. The p-value of 0.057 indicates no difference between the Australia and other groups.

To test the inter-country proposition in general, we have compared the 7 Canadian energy firms with the 44 firms from the USA. We exclude the Canadian firm Hydro One from this analysis to leave firms that are vertically integrated in both countries.

The Bayesian model estimates the most likely difference in the means is 0.43 and there is a 99% probability that the difference in equity betas between the Canadian group and USA group exceeds a threshold of 0.05. The model also estimates that if one firm is selected at random from each group, the Canadian firm would have a higher equity beta about 82% of the time, which indicates high confidence can be placed on there being a meaningful difference between the two groups.[67]

We have concluded that the evidence supports our prior view that there is a material difference in equity betas between countries, as well as supports our prior view that there is a material difference in equity betas between pure-play and other energy firms.

On this basis, we consider that most weight should be placed on the Australian pure-play firms and that the AER's analysis would be biased if it placed too much weight on the international pure-play firms.

4.5 What method should be used to account for differences in leverage between firms?

Once the set of international comparators has been formed a decision is needed about how to convert international raw equity beta data into a form that accounts for differences in leverage between international firms and NSPs in Australia.

The method of conversion depends on whether:

- the regulator applies a notional leverage which differs from the average leverage of the comparator set; and
- a debt beta is used to convert the raw equity betas of individual firms to asset betas. A debt beta is intended to capture the exposure of a firm's debt to movements in the overall market.

The method of conversion is complicated by an issue referred to as the leverage anomaly. This anomaly occurs because the WACC formula that is generally applied by regulators (such as the one used by the AER) results in a higher WACC when leverage is increased even though this is in contravention to finance theory which says there should be no change in the WACC in this situation.

[67] We have also calculated the p-values for the Canada - USA comparison using the Welch t-test. The average raw equity beta is 1.02 for Canada and 0.63 for the USA. The p-value of 0.026 indicates it would be surprising if there were no difference between the Canada and USA groups.

To illustrate the options, we have used the data for National Grid in the UK, which has a raw equity beta of 0.58 and leverage of 0.45. How should the AER make use of this information if it wanted to apply a benchmark leverage of 0.60 to NSPs?

- For illustrative purposes, when calculating the WACC, we have used the market parameters for the Ausgrid determination in 2024.
- The second and third columns of Table 5 shows that the use of a debt beta in converting the raw equity beta to an asset beta does not affect the resulting WACC if the actual leverage of the firm is used in the conversion process. This result holds irrespective of the choice of debt beta (we return to this issue below).
- However, the fourth column shows that if the AER were to apply this information to NSPs in Australia, by converting the National Grid raw equity beta to an asset beta without using a debt beta, and by applying an assumed benchmark leverage of 60%, the resulting WACC would increase to 6.45%. This is the result of the leverage anomaly.
- A solution is to use the approach shown in the fifth column, which is to assume a debt beta when converting the raw equity beta to an asset beta, which brings the WACC back down to 6.38%. It should be noted here that this result depends on the value of debt beta. The debt beta used in this table is the 0.075 value used by Ofgem, but if a higher debt beta is used (such as the 0.125 used by the QCA) the WACC would be reduced below 6.38%.
- An alternative solution, as shown in the second column, is to use the average leverage of the firm and not use a debt beta as this also maintains the WACC at 6.38%.

Table 5. Illustration of different methods of converting international data for use in Australia, using National Grid

	No debt beta/average leverage	Debt beta/average leverage	No debt beta/notional leverage	Debt beta/notional leverage
Nominal risk-free rate	4.19%	4.19%	4.19%	4.19%
Cost of debt margin	0.46%	0.46%	0.46%	0.46%
Nominal pre-tax cost of debt	*4.65%*	*4.65%*	*4.65%*	*4.65%*
Market risk premium	6.20%	6.20%	6.20%	6.20%
Equity beta (raw)	0.58	0.58	0.58	0.58
Asset beta (unlevered)	0.32	0.35	0.32	0.35
Equity beta (re-levered)	0.58	0.58	0.80	0.77
Post-tax nominal return on equity	*7.80%*	*7.80%*	*9.15%*	*8.96%*
Proportion of equity funding	55%	55%	40%	40%
Proportion of debt funding	45%	45%	60%	60%
Corporate tax rate	30%	30%	30%	30%
Nominal vanilla WACC	***6.38%***	***6.38%***	***6.45%***	***6.38%***

Different regulators use different methods. Ofgem, Ofwat and QCA use a debt beta while the Commerce Commission does not use a debt beta but uses the average leverage of the comparator set.

As indicated above, if the AER chose to set leverage at the average of a comparator set, the choice of debt beta would not matter. This is illustrated in Table 6, which shows the WACC values for the pure-play comparator set are invariant to the choice of debt beta value. The asset beta changes as raw equity betas are converted, but the equity beta value does not change.

Table 6. Illustration of WACC for pure-play comparator set using average leverage and different values of debt beta

	Debt beta = 0	Debt beta = 0.075	Debt beta = 0.125
Number of firms	6	6	6
Nominal risk-free rate	4.19%	4.19%	4.19%
Cost of debt margin	0.46%	0.46%	0.46%
Nominal pre-tax cost of debt	*4.65%*	*4.65%*	*4.65%*
Market risk premium	6.20%	6.20%	6.20%
Asset beta	0.25	0.29	0.31
Equity beta	0.50	0.50	0.50
Post-tax nominal return on equity	*7.29%*	*7.29%*	*7.29%*
Proportion of equity funding	49%	49%	49%
Proportion of debt funding	51%	51%	51%
Corporate tax rate	30%	30%	30%
Nominal vanilla WACC	***5.94%***	***5.94%***	***5.94%***

The decision about whether to apply a debt beta depends on whether the AER applies a notional leverage that differs from the average of the comparator set. We consider this decision is informed by whether there is a statistically significant difference between the mean leverage of the Australian firms in the comparator set and the mean leverage of the other firms in the comparator set.

The Bayesian model indicates the most likely difference in the means is 0.08 (Australia higher) and there is a 75% probability that the difference in leverage between the two groups exceeds a threshold of 0.05. There is a 61% probability that a new observation from the Australian group would have a higher leverage than a new observation from the other pure-play group.[68]

On this basis, our view is that the evidence that Australia NSPs have a higher leverage than the three international firms in the comparator set is relatively weak. It is therefore open to the AER to use the average leverage of the comparator set, and consequently not use a debt beta.

However, we would understand if the AER were reluctant to move away from the notional leverage of 60% for various reasons, including the historical precedent for using this value, the typical use of this value by other economic regulators such as Ofgem, and the consistency with the view that it provides sustainable financing outcomes for the regulatory context. We also

[68] The Welch t-test provides a p-value of 0.442.

note the AER's RoRE analysis indicates that a reason provided for excess returns relative to the benchmark is that NSPs have increased their leverage positions above 60%.[69]

If the AER does decide to maintain the 60% leverage assumption, then we consider the debt beta should be set at 0.125, which is the value used by Ofwat and QCA. As is shown in Table 7 a debt beta of 0.125 results in a WACC for the pure-play comparator set that is closest to the WACC that is calculated using average leverage.

Table 7. WACC for the pure-play comparator set from differing debt beta assumptions

	Debt beta = 0[70]	Debt beta = .075	Debt beta = 0.125
Number of firms in the sample		6	6
Nominal risk-free rate	4.19%	4.19%	4.19%
Cost of debt margin	0.46%	0.46%	0.46%
Nominal pre-tax cost of debt	*4.65%*	*4.65%*	*4.65%*
Market risk premium	6.20%	6.20%	6.20%
Asset beta	0.25	0.29	0.31
Equity beta	0.50	0.60	0.59
Post-tax nominal return on equity	*7.29%*	*7.92%*	*7.85%*
Proportion of equity funding	49%	40%	40%
Proportion of debt funding	51%	60%	60%
Corporate tax rate	30%	30%	30%
Nominal vanilla WACC	***5.94%***	***5.96%***	***5.93%***

4.6 What is the appropriate equity beta/leverage combination for application to Australia?

Table 8 compares the WACC from using the pure-play comparator set against the existing WACC used by the AER.

[69] See AER, 2024 Electricity and Gas Networks Performance Report (September 2024), Figure 5-5 Detailed contributions to real RoRE – electricity NSPs and gas DNSPs - 2023, page 80. See also page 21 discussion on capital structure in Power prices can be fairer and more affordable (November 2023), Simon Orme for IEEFA.

[70] Note for this column that we have calculated the WACC by setting the debt beta to zero in the calculation of the equity beta. If we had ignored the debt beta, the value of equity beta would be 0.51 and the resulting WACC would have been 5.97%. We consider the AER should consider this matter further. We understand the AER re-levers the asset betas by dividing by (1-leverage). The alternative is to use the formula: (raw equity beta x E/V) + D/E * (raw equity beta x E/V).

Table 8. WACC from existing AER settings compared to WACC from pure-play comparator set

	AER existing	Pure-play
Number of firms in the sample		6
Nominal risk-free rate	4.19%	4.19%
Cost of debt margin	0.46%	0.46%
Nominal pre-tax cost of debt	*4.65%*	*4.65%*
Market risk premium	6.20%	6.20%
Asset beta	0.24	0.31
Equity beta	0.60	0.59
Post-tax nominal return on equity	*7.91%*	*7.85%*
Proportion of equity funding	40%	40%
Proportion of debt funding	60%	60%
Corporate tax rate	30%	30%
Nominal vanilla WACC	***5.95%***	***5.93%***

As the resulting WACC of 5.93% is similar to the WACC that is calculated using the existing beta/leverage combination (5.95%) we consider this pure-play comparator set is consistent with the AER's existing view of the level of systematic risk facing NSPs in Australia.

As indicated above, however, the evidence indicates that mean equity betas differ across countries and, in particular, between the Australian pure-play firms and the international pure-play firms. In addition, our analysis of the existing rules and arrangements supports the view that NSP's in Australia are substantially protected from risk.

Table 9 shows the WACC for the Australian pure-play group is lower than the WACC for the international pure-play group.

Table 9. WACCs for Australian and international pure-play groups

	Australia	International
Number of firms in the sample	3	3
Nominal risk-free rate	4.19%	4.19%
Cost of debt margin	0.46%	0.46%
Nominal pre-tax cost of debt	*4.65%*	*4.65%*
Market risk premium	6.20%	6.20%
Asset beta	0.26	0.36
Equity beta	0.46	0.72
Post-tax nominal return on equity	*7.07%*	*8.63%*
Proportion of equity funding	40%	40%
Proportion of debt funding	60%	60%
Corporate tax rate	30%	30%
Nominal vanilla WACC	***5.62%***	***6.24%***

Our conclusion from the comparator sample analysis is that the equity beta for this RoRI should be set no higher than 0.5 (assuming a debt beta of 0.125 and a notional leverage of 60%).

4.7 The value of cross checks

In its 2025 RoRI Discussion Paper, the AER does not identify cross checks of the overall rate of return as a significant issue that requires review in the 2026 RoRI review.

In its Explanatory Statement for the 2022 RoRI review, the AER states that 'Our use of historical profitability has … remained the same, as neither the 2018 nor 2022 review used it in any material way when deciding the overall rate of return'.[71] This view appears to be based on the view that historical profitability is backward looking, whereas the RoRI is forward looking.

Our analysis highlights the importance of applying cross checks of the overall rate of return, for the following reasons.

- The Revenue and Pricing Principles refer to price outcomes not to pricing intentions. Where price outcomes, as indicated by historical return on equity data, vary significantly from ex-ante expectations, identifying whether these price variations are consistent with the revenue and pricing principles as applied to the RoRI, is entirely relevant to RoRI decisions.

[71] See page 272 of Op. Cit. AER, February 2023.

- For the RoRI decisions to be evidence-based, they must be capable of being tested (and falsified) by actual (ex-post) data. The 2022 RoRI estimate relies on a regulatory judgment to include firms in the comparator set that do not hold statutory monopolies for most of their revenue (see Figure 10).

- The profitability data published by the AER indicates that NSPs are benefiting from varying their leverage from the benchmark assumed in the RoRI:

    - Historical profitability data indicate there are persistent and significant differences between benchmark leverage and leverage applied across the sector.[72]

    - As shown in Figure 11, while leverage is significantly higher than the 60% benchmark, the cost of debt is significantly lower.[73] Both these differences have been sustained since 2016 and are therefore not short term.

    - Finance theory suggests that, under idealised conditions, WACC is invariant to leverage.[74] As leverage increases, the cost of equity rises, due to the increase in overall systematic risk. We consider it is likely that the reason NSPs can sustainably increase their leverage above the benchmark level is because the actual equity beta is lower than the benchmark level.

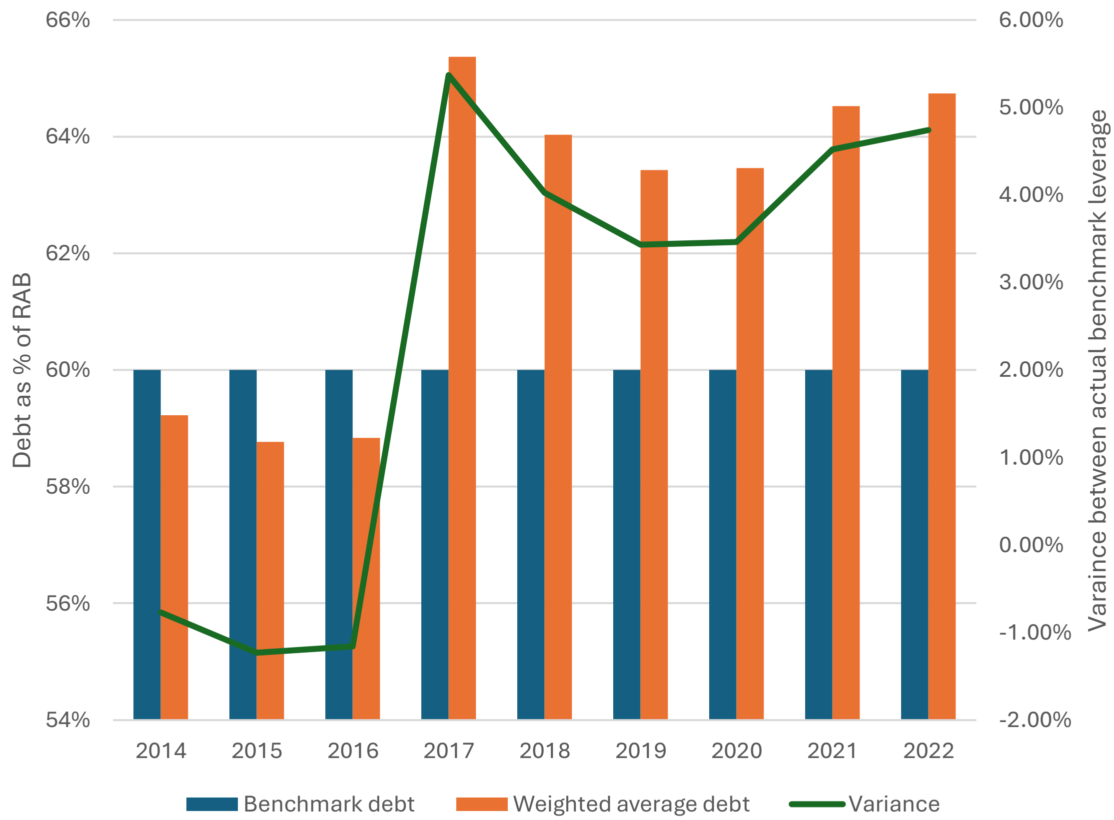
Together with the fundamental and probabilistic analysis set out above, cross checking historical data on actual leverage and debt financing provides further evidence the current RoRI equity beta estimate is too high.

[72] AER, 2024 Electricity and Gas Networks Performance Report (September 2024), Figure 5-5.

[73] The AER does not publish leverage data in its annual network performance reports, but these were provided to one of the present authors, on request in November 2023.

[74] See Modigliani, F., & Miller, M. H. The Cost of Capital, Corporation Finance and the Theory of Investment. American Economic Review, Vol. 48, No. 3, (1958) pp. 261–297.

Figure 11. Benchmark vs. actual leverage for electricity NSPs - 2014-2022



Source: Correspondence from AER, 15 August 2023

4.8 The term of the risk-free rate for the return on equity

At the last RoRI review, the AER's draft decision was to change the term of the risk-free rate for the return on equity from 10 years to 5 years. The draft decision to adopt a 5-year term appears to have been based on the view that investors in NSPs have the opportunity every five years to reassess their investment, based on an independent assessment of the business by the AER, and a reset of the real return on equity underlying the regulated revenue allowance.

However, the AER's final decision was to maintain a 10-year term. The reason for retaining a 10-year term was based on a reconsideration of the decision-making framework rather than any change in evidence. In the final decision the AER appears to have applied a decision-making framework that ensured the status quo would be retained when there were finely balanced reasons for and against making a change.

Interestingly, the AER considered that NPV=0 would be achieved if the term for the return on equity was set at either 10 years or 5 years.

The AER appears to have defined NPV=0 as a condition that is achieved when the present value of revenue equals the present value of costs, where the costs are as assumed by the AER. Therefore NPV=0 is achieved if the investor makes a long-term ‘set and forget’ investment, and NPV=0 is also achieved if the investor makes a long-term investment which is reassessed every 5-years.

This interpretation implies NPV=0 is achieved even if the IRR of two scenarios produces different results. For example, an investor will achieve a different IRR by adopting one strategy (an ongoing 5-year reassessment of their investment) over another strategy (no reassessment, using a 10-year term as the proxy), but according to the AER the NPV=0 condition will still hold.[75]

Our view is that the AER should define NPV=0 as occurring when:

a) the present value of revenue equals the present value of costs; and

b) the internal rate of return is as low as possible without compromising incentives to invest.

Based on this definition, allowing an investor to earn a higher IRR by setting the term at 10 years, without concluding that setting the term at 5 years would compromise incentives to invest, would be inconsistent with NPV=0.

In our view the move to a 5-year term for the return on equity would not compromise an NSP investor’s incentive to invest as that has not been the experience in regulatory settings where the 5-year term has been applied, such as in Western Australia and in New Zealand.

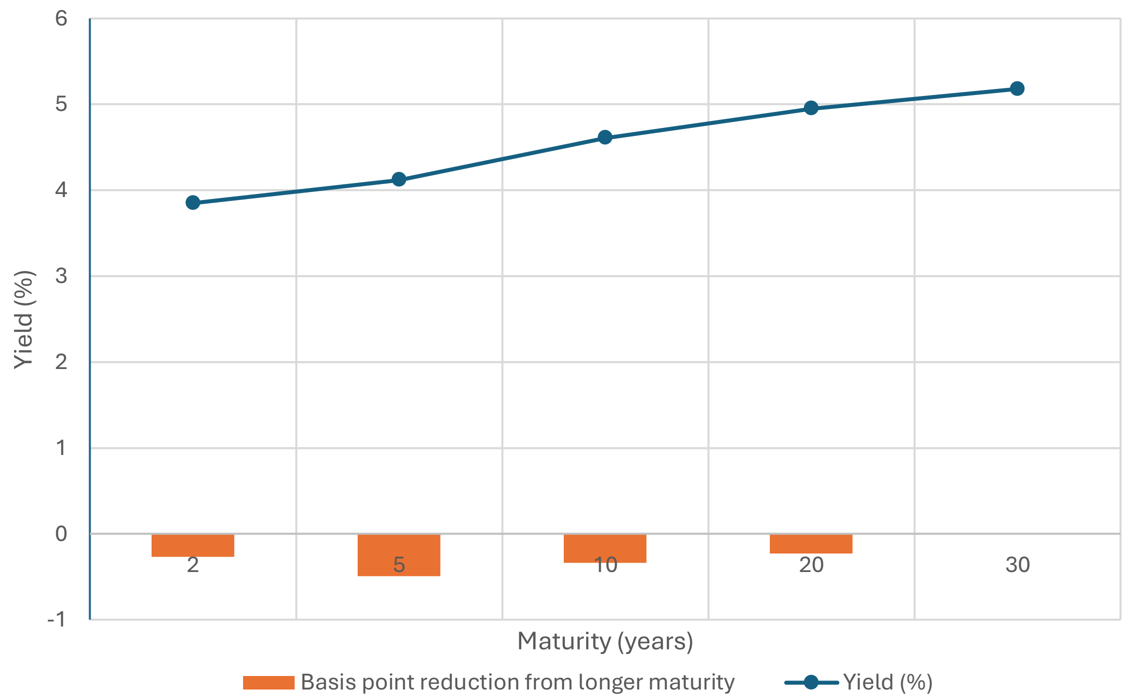
We also consider that, when two RoRI options are being considered, the one that provides the lowest IRR without compromising incentives to invest is the one that is most consistent with the Revenue and Pricing Principles.

Our recommendation is that the AER adopt a 5-year term for the risk-free rate for the return on equity as that is consistent with our proposed definition of NPV=0 and the Revenue and Pricing Principles.

On 1 December 2025, the use of a 10-year term increased the allowed return on equity by 50 basis points. This is shown in Figure 12. We have quantified in section 2.3 the value to consumers of changing from a 10-year to 5-year assumption.

[75] The IRR is higher for the 10-year scenario because of the yield curve is generally positive.

Figure 12. Australian Government Bond Yield Curve and Impact of 10 versus 5 Year Term (1 December 2025)

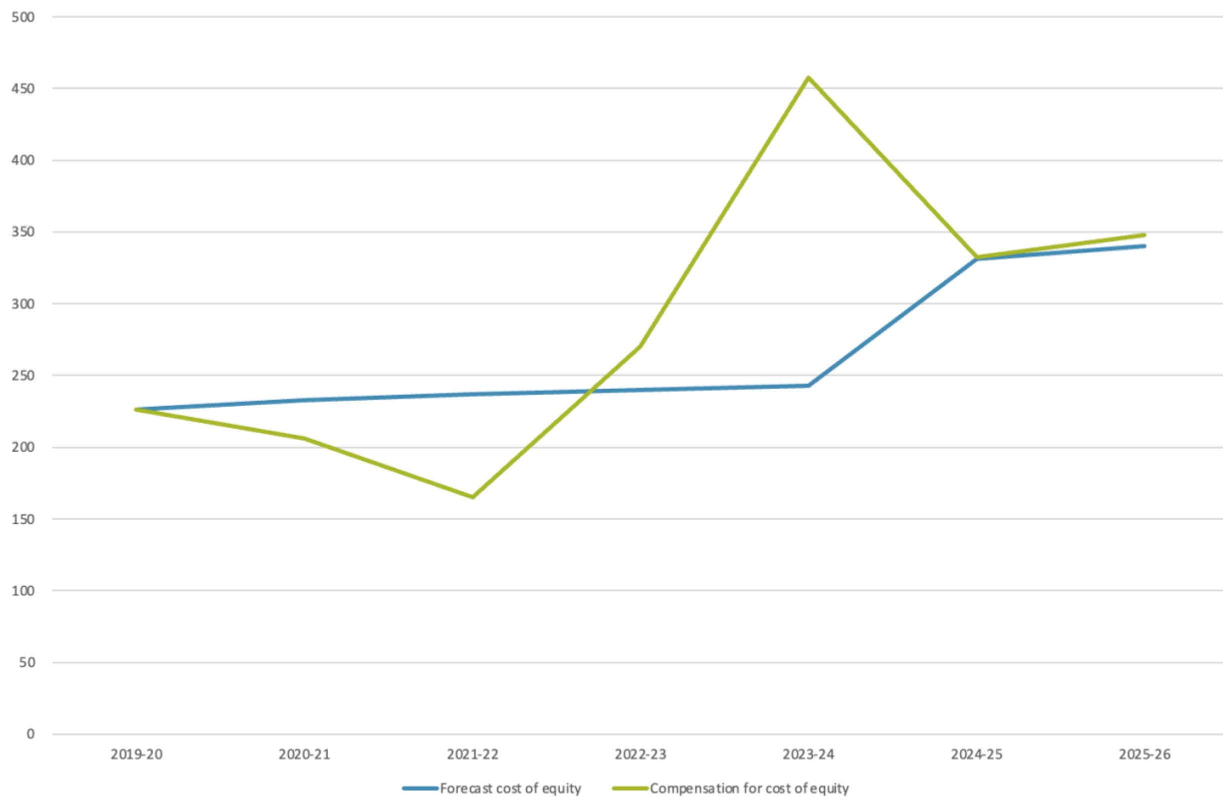


Source: *1 December 2025 • YieldReport*

4.9 Addressing the potential for windfall gains or losses to equity investors

We also recommend a change to the calculation of the return on equity underlying annual revenue allowances to address the potential for windfall gains or losses to equity investors as a result of unexpected inflation. Figure 13 shows the effect of unexpected inflation on the actual cost of equity underlying Ausgrid's revenue allowance, which varies substantially from what was expected at the reset.

Figure 13. Forecast cost of equity and actual compensation for cost of equity (including realised and unrealised gains), Ausgrid Distribution



We consider the appropriate way to deal with this issue is by making a RAB adjustment at each reset to provide a true-up for unexpected inflation. The true-up would depend on whether the term of the return on equity was assumed to be 5 years or 10 years.

- If the term were 5 years, with the assumption that equity investors reassess their investment at every reset, the RAB adjustment would ensure the nominal return on equity throughout the regulatory period was equal to the nominal return forecast at the reset. This adjustment would benefit NSPs and consumers by removing the windfall gains and losses under the status quo.
- If the term were 10 years, with the assumption that equity investors 'set and forget' their investment, the RAB adjustment would account for the difference between the return on equity over a regulatory period under the status quo and the return on equity had the risk-free rate been updated annually. The updated risk-free rate would embody the expected inflation rate, which would avoid the current problem with defining the real return on equity using the actual inflation rate. This adjustment to the definition of the real return on equity would effectively apply expected inflation rates underlying the risk-free rate instead

of actual inflation rates. It would benefit NSPs and consumers by removing the windfall gains and losses associated with the actual return on equity under the status quo.

4.10 Comment on the Eligible Experts' findings

Our main takeaways from the Eligible Experts' review of equity beta are that the Eligible Experts:

- have little confidence in the value of equity beta in the existing RoRI; however, they provide no specific guidance on the value that should be adopted by the AER.
- recognise that using international data is fraught with difficulty and there is little theoretical guidance in how to make use of the international data; but acknowledges that the existing approach of using delisted firms is unsustainable.
- have attempted to identify filters that could be used to identify eligible comparator firms – specifically, Partington has proposed filters for profitability, volatility and rates of return.
- acknowledge that the current value of equity beta is biased upwards as a result of not using a debt beta in the past.
- reject the use of average leverage from the comparator set rather than a notional value of leverage.
- recognise that the Australian tax system and domestic regulatory settings result in a lower asset beta / higher leverage combination in Australia than overseas.
- note there is circularity in estimating the equity beta as it is influenced by the regulatory settings, including of the equity beta.
- recognise that it is theoretically valid to include some factors that affect non-systematic risk in the CAPM; although cautions that if these factors are already recognised through, for example, accelerating depreciation to accommodate stranding risk, that is does not warrant an increase in the equity beta.

We agree with these findings. Importantly, they have not caused us to reconsider our recommended equity beta. The AER will need to apply regulatory judgment which is informed by qualitative and quantitative analysis. We recognise the challenges associated with making use of international data but also recognise that the AER must choose a value of equity beta.

There are some aspects of the Eligible Experts' findings that we disagree with. We disagree with the proposition by one expert that a larger comparator set is preferable to a smaller set even if the larger set includes firms that are not comparable to NSPs. In particular, the Eligible Experts appear to be less concerned than we are over the difference between regulated energy utilities and energy network monopolies. The term energy “utility” appears 28 times in their report while network “monopoly” appears only once. However, we note that one expert recognises the importance of including only firms that are comparable to NSPs (by referencing the analogy that is not appropriate to estimate the height of spaniels from a sample that includes great danes).

We also consider the Eligible Experts have not fully appreciated the importance of cross checks. While one expert referred to real return on equity outturn data published in Network Performance Reports, which is welcome, another expert was under the misapprehension that increased sector-wide leverage reflected a higher tolerance for risk. In our view, the higher leverage, combined with the fact sector-wide actual debt costs have been lower than allowed debt costs, indicates the extent NSPs are protected from risk rather than have a higher tolerance for risk.

More generally, references by the Eligible Experts to asset stranding and other risks suggest some of the Experts may not be aware of the extent NSPs are protected from risk under the regulatory framework.

We recommend the AER adopt the approach we have followed, which in our view works through in a methodical way the steps that need to be followed to inform the AER’s choice of equity beta. These steps involve:

- establishing the qualitative evidence for the exposure of NSPs to systematic risk;
- establishing the quantitative evidence, which involves:
    - identifying valid comparator firms, both domestically and internationally using an appropriate filtering method;
    - verifying the statistical basis for not using a larger set of firms;
    - determining the method that will be used to convert the individual firm data to an average for application to NSPs in Australia (while recognising the weak theoretical basis for how this is done);
    - determining notional leverage; and
    - establishing the extent the international and domestic data informs the value of equity beta applicable to NSPs.
- applying regulatory judgment on the basis of the qualitative and quantitative evidence to arrive at the values of equity beta and leverage.

Based on our analysis, we have concluded that the existing value of 0.6 cannot be sustained from any evidence that we have considered, and that a more appropriate value of equity beta is 0.5 or below.

Appendix A. Method to calculate the weighted portfolio return on debt

We have modelled a weighted TAPRD by modifying our model of NSP revenue (the EMAS NSP Model).

The EMAS NSP Model incorporates into one model the three steps associated with calculating an NSP's revenue allowance. The first step is the approximation of the PTRM, which is used to calculate an NSP's forecast revenue and X factors. The second step is the annual update to the return on debt, which involves the recalculation of X factors. The third step is the adjustment to allowable revenue for the applicable inflation rate and X factor for the relevant year.

We have modified the EMAS NSDP Model as follows.

The method used at a reset to forecast the RAB (Table 10) and revenue (Table 11) remains unchanged, albeit with expenditure calculated using the forecast weighted TAPRD rather than the forecast uniform TAPRD.

The NSP's asset base is calculated using the opening RAB at the time the new regime is implemented as the starting asset value, the same depreciation rate as used for the RAB, and actual capex (Table 12). This asset base is rolled forward each year.

- The asset base rather than the RAB is used because it is not affected by revaluations for inflation, which would distort the calculation of borrowing requirements.

At the annual review, the NSP's opening value of debt for each year is calculated using the opening asset base for each year multiplied by the benchmark leverage (Table 13).

- The repayment of existing debt is deducted from the opening value of existing debt.
- For the first 10 years of the new regime, the repayment of debt for each year is assumed to be 10% of the initial value, which is consistent with the uniform debt financing assumption underlying the existing portfolio of debt.
- Thereafter, a deduction for the repayment of debt is zero as this deduction is only relevant for the initial debt position at the start of the new regime.
- For each year, the opening value of debt less the repayment of debt is compared to the target level of debt (using the leverage value) with the difference being the additional borrowing requirement for the year.

The weighted TAPRD is calculated using weights based on the existing debt and additional debt raised each year (Table 13).

- For the debt existing at the start of the new regime, the assumption is that 10% of the debt is repaid each year, which means that the oldest interest rate drops out each year. For example, as shown in Table 14, the interest rate for 2029 is the interest rate for 2020 as the only remaining debt at that time is the debt assumed to be raised in 2020. The interest rate for 2028 is the average interest rate for 2020 and 2019, etc.

The weighted TAPRD is an input for the calculation of the revised X factor for the year (Table 15).

Allowable revenue is calculated using the applicable inflation rate and the revised X factor for the year (Table 16).

Table 10. Illustration of step 1: calculation of forecast RAB at resets, Ausgrid distribution

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Opening RAB	13,779	14,273	14,678	15,011	15,315	15,885	16,401	16,855	17,309	17,711
Revaluation	334	346	356	364	371	423	436	448	460	471
Capex	587	525	479	477	476	614	578	608	576	552
Depreciation	(427)	(467)	(502)	(536)	(543)	(520)	(560)	(602)	(634)	(621)
Closing RAB	14,273	14,678	15,011	15,315	15,620	16,401	16,855	17,309	17,711	18,113

Table 11. Illustration of step 1 (continued): calculation of forecast revenue at resets, Ausgrid distribution

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Revenue	1,447	1,450	1,452	1,455	1,458	1,538	1,600	1,665	1,733	1,803
Return on debt	(474)	(475)	(472)	(465)	(457)	(443)	(469)	(497)	(527)	(559)
Return on equity	(314)	(325)	(335)	(342)	(349)	(503)	(519)	(533)	(548)	(560)
Revaluation	334	346	356	364	371	423	436	448	460	471
Tax	(38)	(28)	(26)	(27)	(21)	(7)	2	(11)	(19)	(19)
Opex	(497)	(465)	(478)	(474)	(505)	(450)	(468)	(492)	(505)	(519)
Depreciation	(427)	(467)	(502)	(536)	(543)	(520)	(560)	(602)	(634)	(621)
Net revenue	30	35	(5)	(25)	(46)	37	23	(23)	(40)	(6)
Present value	28	32	(4)	(20)	(36)	27	15	(15)	(24)	(3)
Sum of present values					0					0

Table 12. Illustration of step 2: calculation of asset base for Ausgrid distribution, 2020 to 2029 ($m)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Opening Asset Base	13,779	13,859	13,746	13,420	13,533	13,783	13,957	14,071	14,188	14,258
Capex	497	329	134	581	718	614	578	608	576	552
Depreciation	(417)	(442)	(459)	(468)	(468)	(439)	(464)	(490)	(506)	(487)
Closing Asset Base	13,859	13,746	13,420	13,533	13,783	13,957	14,071	14,188	14,258	14,323

Table 13. Illustration of step 3: calculation of additional borrowings for Ausgrid distribution, 2020 to 2029 ($m)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Opening debt	8,268	8,316	8,247	8,052	8,120	8,270	8,374	8,442	8,513	8,555
Repayment of debt	(827)	(827)	(827)	(827)	(827)	(827)	(827)	(827)	(827)	(827)
Net	7,441	7,489	7,421	7,225	7,293	7,443	7,547	7,616	7,686	7,728
Target debt position (closing balance)	8,316	8,247	8,052	8,120	8,270	8,374	8,442	8,513	8,555	8,594
Additional borrowings	875	759	631	894	977	931	895	897	869	866
Opening equity	5,512	5,544	5,498	5,368	5,413	5,513	5,583	5,628	5,675	5,703
Retained earnings	14	35	53	(2)	(373)	82	73	75	80	90
Net	5,525	5,579	5,551	5,366	5,040	5,595	5,656	5,703	5,755	5,793
Target equity position (closing balance)	5,544	5,498	5,368	5,413	5,513	5,583	5,628	5,675	5,703	5,729
Additional equity	18	(80)	(183)	47	473	(12)	(28)	(28)	(52)	(64)

Table 14. Illustration of step 4: calculation of weighted TAPRD for Ausgrid distribution, 2020 to 2029 ($m)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Existing debt - opening balance	8,268	7,441	6,614	5,787	4,961	4,134	3,307	2,480	1,654	827
- repayment	(827)	(827)	(827)	(827)	(827)	(827)	(827)	(827)	(827)	(827)
- closing balance	7,441	6,614	5,787	4,961	4,134	3,307	2,480	1,654	827	(0)
- prevailing rate	**5.74%**	5.65%	5.54%	5.41%	5.22%	4.97%	4.83%	4.77%	4.70%	4.59%
2021 - borrowings		875	875	875	875	875	875	875	875	875
- interest rate		**2.87%**	2.87%	2.87%	2.87%	2.87%	2.87%	2.87%	2.87%	2.87%
2022 - borrowings			759	759	759	759	759	759	759	759
- prevailing rate			**2.12%**	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%	2.12%
2023 - borrowings				631	631	631	631	631	631	631
- prevailing rate				**3.40%**	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
2024 - borrowings					894	894	894	894	894	894
- prevailing rate					**6.77%**	6.77%	6.77%	6.77%	6.77%	6.77%
2025 - borrowings						977	977	977	977	977
- prevailing rate						**6.51%**	6.51%	6.51%	6.51%	6.51%
2026 - borrowings							931	931	931	931
- prevailing rate							**5.91%**	5.91%	5.91%	5.91%
2027 - borrowings								895	895	895
- prevailing rate								**5.91%**	5.91%	5.91%
2028 - borrowings									897	897
- prevailing rate									**5.91%**	5.91%
2029 - borrowings										869
- prevailing rate										**5.91%**

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Total debt (opening balance)		8,316	8,247	8,052	8,120	8,270	8,374	8,442	8,513	8,555
Weighted TAPRD	**5.74%**	**5.36%**	**4.95%**	**4.66%**	**4.71%**	**4.74%**	**4.80%**	**4.89%**	**5.00%**	**5.11%**

Table 15. Illustration of step 5: calculation of revised X factor for 2020-21 for Ausgrid distribution ($m)[76]

	2019-20	2020-21	2021-22	2022-23	2023-24
Revenue	1,447	1,446	1,448	1,451	1,454
Return on debt	(474)	(460)	(472)	(465)	(457)
Return on equity	(314)	(325)	(335)	(342)	(349)
Revaluation	334	346	356	364	371
Tax	(38)	(28)	(26)	(27)	(21)
Opex	(497)	(465)	(478)	(474)	(505)
Depreciation	(427)	(467)	(502)	(536)	(543)
Net revenue	30	46	(9)	(29)	(50)
Present value	28	41	(8)	(23)	(39)
Sum of present values					**0**
Revised X factor					-2.46%

[76] Note that the revised X factor is calculated using the forecast RAB.

Table 16. Illustration of step 6: calculation of allowable revenue for 2020-21 for Ausgrid distribution

	2019-20	2020-21
Applied Inflation rate		1.84%
X factor		-2.46%
CPI-X adjustment	1.00	0.993
Allowable revenue ($m)	1,447	1,437

Appendix B. Historical capex and interest rates

The following figures show the variation in capex over time and compared to prevailing interest rates. Forecast capex is generally evenly spread over the regulatory period, whereas actual capex varies substantially and has increased post 2021-22.

The data in the appendix has been sourced from the PTRM and RFM models for each NSP that were published by the AER at the resets.

Figure 14. Forecast and actual nominal capex, and nominal interest rates for Transgrid ($m)

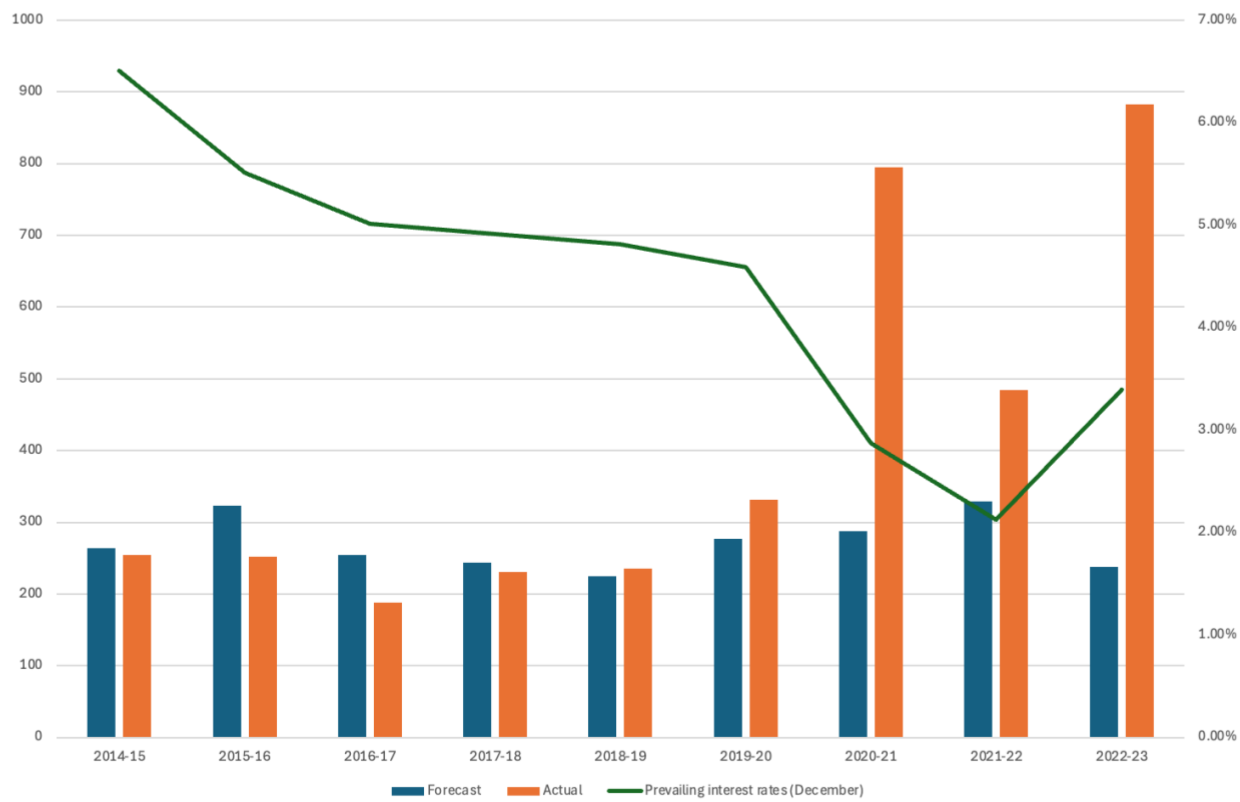
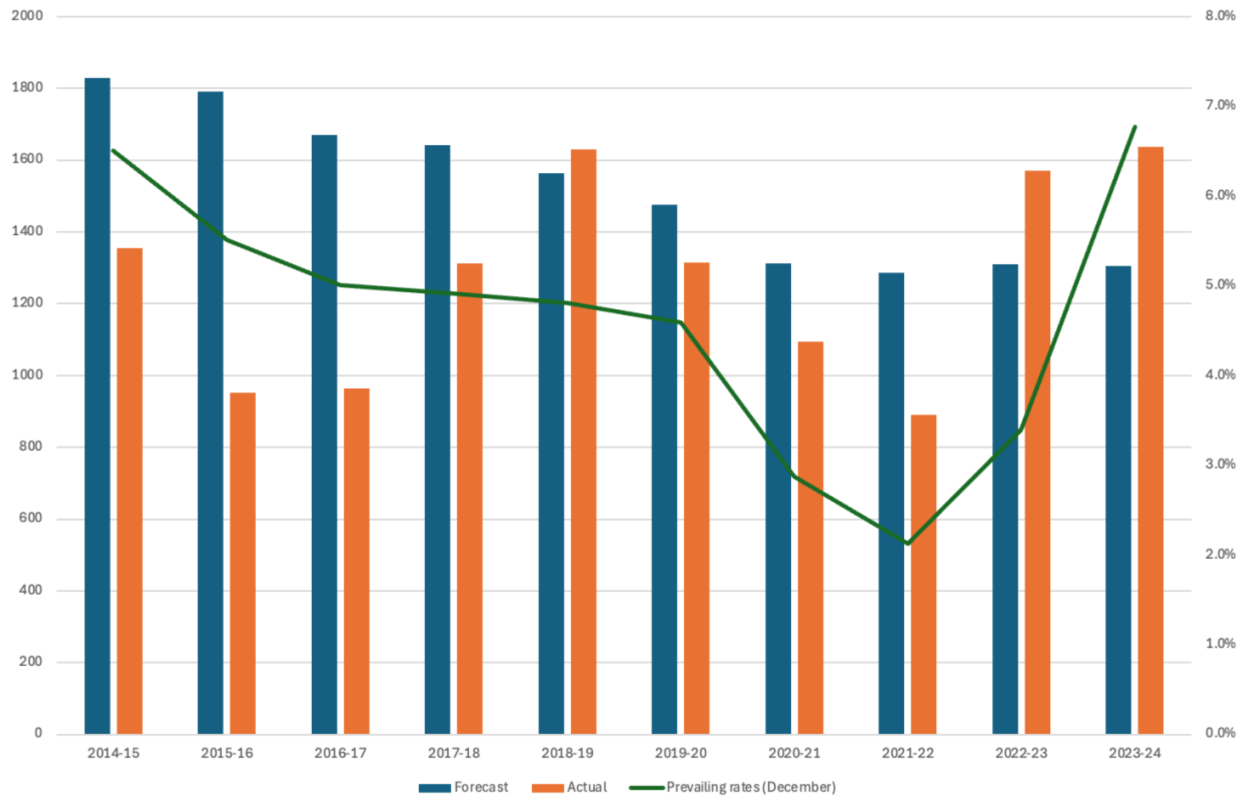
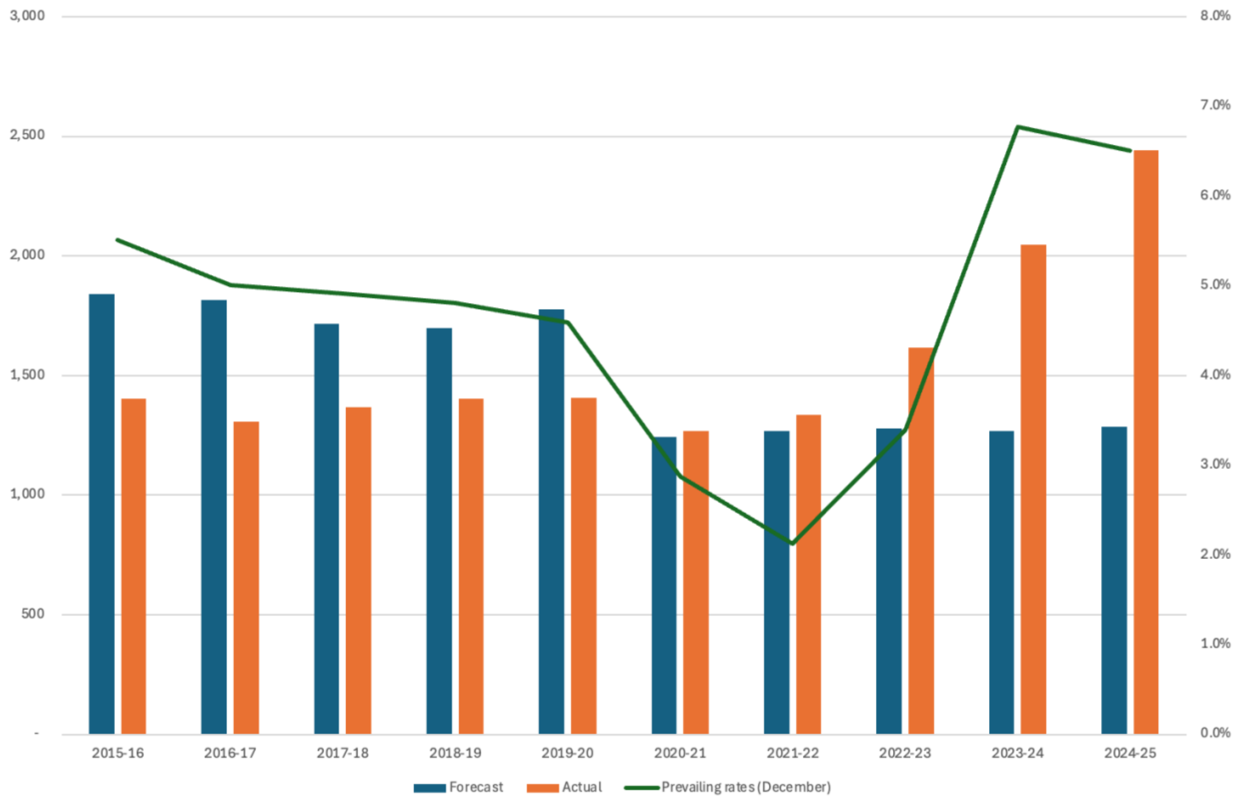


Figure 15. Forecast and actual nominal capex, and nominal interest rates for NSPs with access arrangements commencing in 2019-20 ($m)[77]



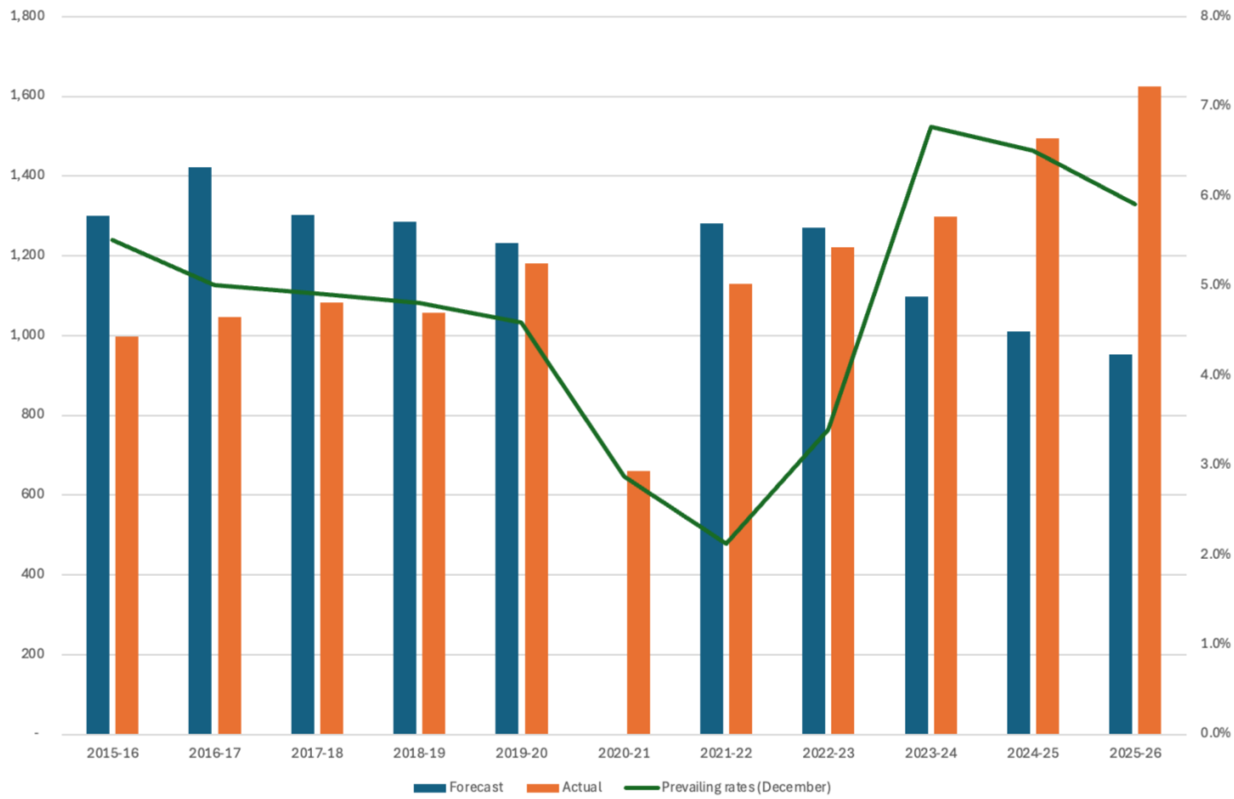
[77] This group includes Ausgrid, Endeavour Energy, Essential Energy

Figure 16. Forecast and actual nominal capex, and nominal interest rates for NSPs with access arrangements commencing in 2020-21 ($m)[78]



[78] This group includes SA Power Networks, Energex and Ergon Energy Network.

Figure 17. Forecast and actual nominal capex, and nominal interest rates for NSPs with access arrangements commencing in 2021-22 ($m)[79]



[79] This group includes Powercor, Ausnet Services, United Energy, Citipower and Jemena. There was no forecast data available for 2020-21 due to the realignment of the commencement of their access arrangements.

Appendix C. Beta and leverage estimates

Ticker	Name	Asset beta, 2007-2012, weekly	Asset beta, 2012-2017, weekly	Asset beta, 2017-2022, weekly	Equity beta, 10 year, OLS	Equity beta, raw, 10 year	Equity beta, raw, 5 year	Leverage, 2007-2020	Leverage 2012-17, 2017-22, average	Leverage, 10 year	Leverage, 10 year	Leverage, 5 year
Australia (source: Commerce Commission[80])												
APA AU Equity	APA Group	0.22	0.37	0.34					0.45			
AST AU Equity	Ausnet Services Ltd	0.12	0.29	0.09					0.54			
DUE AU Equity	DUET	0.14	0.12						0.71			
SKI AU Equity	Spark Infrastructure Group	0.23	0.30						0.41			
Canada (source: ERA[81])												
ALA CN Equity	Altagas LTD				1.56					0.47		
AQN CN Equity	Algonquin Power & Utilities				1.02					0.39		
CU CN Equity	Canadian Utilities Ltd-A				0.99					0.46		
EMA CN Equity	Emera Inc				0.60					0.52		
FTS CN Equity	Fortis Inc				1.22					0.42		
H CN Equity	Hydro One Ltd				0.64					0.52		
TRP CN Equity	TC Energy				0.57					0.47		
ENB CN Equity	Enbridge Inc				1.16					0.45		
Italy (source: Ofgem[82])												
TRN MI Equity	Terna					0.74					0.43	

[80] Commerce Commission, Cost of Capital Topic Paper, Part 4 Input Methodologies Review 2023 – Final Decision (13 December 2023), Table E3 for asset betas, Table E1 for leverage.

[81] Economic Regulation Authority, Explanatory Statement for the 2022 Final Gas Rate of Return Instrument (16 December 2022), Appendix 6.

[82] Ofgem, RIIO-3 Sector Specific Methodology Decision – Finance Annex (18 July 2024), Table 7 for raw betas, Table 8 for leverage.

Ticker	Name	Asset beta, 2007-2012, weekly	Asset beta, 2012-2017, weekly	Asset beta, 2017-2022, weekly	Equity beta, 10 year, OLS	Equity beta, raw, 10 year	Equity beta, raw, 5 year	Leverage, 2007-2020	Leverage 2012-17, 2017-22, average	Leverage, 10 year	Leverage, 10 year	Leverage, 5 year
SRG MI Equity	Snam					0.80					0.46	
IG MI Equity	Italgas						0.76					0.52
United Kingdom (source: Commerce Commission)												
CNA LN Equity	Centrica PLC	0.44	0.64	0.73					0.29			
NG/ LN Equity	National Grid PLC	0.24	0.38	0.26					0.45			
SSE LN Equity	SSE PLC	0.37	0.53	0.54					0.33			
New Zealand (source: Commerce Commission)												
VCT NZ Equity	Vector Ltd	0.18	0.29	0.27					0.44			
Spain (source: Ofgem)												
ENG MC Equity	Enagas					0.62					0.44	
RED MC Equity	Red Elec					0.54					0.39	
USA (source: Commerce Commission)												
AEE US Equity	Ameren Corporation	0.36	0.30	0.34					0.38			
AEP US Equity	American Electric Power	0.30	0.27	0.30					0.42			
AES US Equity	AES Corp	0.44	0.37	0.44				0.66				
ALE US Equity	Allete Inc	0.41	0.37	0.45					0.33			
ATO US Equity	Atmos Energy Corp	0.32	0.37	0.39					0.31			
AVA US Equity	Avista Corp	0.34	0.31	0.27					0.42			
BKH US Equity	Black Hills Corp	0.43	0.41	0.40					0.45			
CMS US Equity	CMS Energy Corp	0.25	0.23	0.29					0.45			
CNP US Equity	Centerpoint Energy Inc	0.30	0.42	0.55					0.45			
D US Equity	Dominion Energy Inc	0.33	0.30	0.31					0.39			

Ticker	Name	Asset beta, 2007-2012, weekly	Asset beta, 2012-2017, weekly	Asset beta, 2017-2022, weekly	Equity beta, 10 year, OLS	Equity beta, raw, 10 year	Equity beta, raw, 5 year	Leverage, 2007-2020	Leverage 2012-17, 2017-22, average	Leverage, 10 year	Leverage, 10 year	Leverage, 5 year
DTE US Equity	DTE Energy Company	0.33	0.26	0.43					0.40			
DUK US Equity	Duke Energy Corp	0.30	0.19	0.29					0.46			
ED US Equity	Consolidated Edison Inc	0.24	0.13	0.21					0.42			
EIX US Equity	Edison International	0.40	0.26	0.43					0.42			
ES US Equity	Eversource Energy	0.30	0.26	0.37					0.38			
ETR US Equity	Entergy Corp	0.32	0.23	0.36					0.51			
EVRG US Equity	Evergy Inc			0.39					0.41			
EXC US Equity	Exelon Corp	0.52	0.26	0.43					0.45			
FE US Equity	First Energy Corp	0.33	0.20	0.31					0.55			
HE US Equity	Hawaiian Electric Inds	0.44	0.40	0.40					0.12			
IDA US Equity	IDACorp Inc	0.33	0.38	0.41					0.30			
KMI US Equity	Kinder Morgan Inc	0.39	0.77	0.55					0.46			
LNT US Equity	Alliant Energy Corp	0.44	0.33	0.39					0.35			
NEE US Equity	Nextera Energy Inc	0.37	0.29	0.55					0.33			
NFG US Equity	National Fuel Gas Co	0.84	0.71	0.41					0.29			
NI US Equity	NiSource Inc	0.31	0.36	0.34					0.48			
NJR US Equity	New Jersey Resources Corp	0.43	0.43	0.50					0.31			
NWE US Equity	NorthWestern Energy Group Inc	0.34	0.29	0.37					0.42			
OGE US Equity	OGE Energy Corp	0.46	0.55	0.52					0.33			
OGS US Equity	One Gas Inc		0.37	0.37					0.33			
OKE US Equity	OneOK Inc	0.50	0.76	1.03					0.39			

Ticker	Name	Asset beta, 2007-2012, weekly	Asset beta, 2012-2017, weekly	Asset beta, 2017-2022, weekly	Equity beta, 10 year, OLS	Equity beta, raw, 10 year	Equity beta, raw, 5 year	Leverage, 2007-2020	Leverage 2012-17, 2017-22, average	Leverage, 10 year	Leverage, 10 year	Leverage, 5 year
PCG US Equity	PG&E Corp	0.24	0.27	0.45					0.48			
PEG US Equity	Public Service Enterprise Gp	0.45	0.33	0.49					0.34			
PNM US Equity	PNM Resources Inc	0.38	0.29	0.37					0.48			
PNW US Equity	Pinnacle West Capital	0.33	0.34	0.39					0.38			
POR US Equity	Portland General Electric Co	0.35	0.29	0.35					0.40			
PPL US Equity	PPL Corp	0.33	0.27	0.46					0.45			
SJI US Equity	South Jersey Industries	0.39	0.40	0.31					0.43			
SO US Equity	Southern Co	0.21	0.18	0.35					0.42			
SR US Equity	Spire Inc	0.34	0.29	0.30					0.41			
SRE US Equity	Sempra Energy	0.46	0.41	0.49					0.38			
SWX US Equity	Southwest Gas Holdings Inc	0.41	0.38	0.38					0.38			
WEC US Equity	WEC Energy Group Inc	0.27	0.23	0.30					0.34			
XEL US Equity	Xcel Energy Inc	0.25	0.22	0.32					0.41			

Appendix D. Reasons for excluding firms from the comparator set

Ticker	Name	Reason for exclusion
Australia		
APA AU Equity	APA Group	Majority of its business is subject to competition absent statutory monopoly.
AST AU Equity	Ausnet Services Ltd	Delisted in February 2022
DUE AU Equity	DUET	Delisted in May 2017
SKI AU Equity	Spark Infrastructure Group	Delisted in late 2021
Canada		
ALA CN Equity	Altagas LTD	Significant exposure to commodity markets and exporting of LNG.
AQN CN Equity	Algonquin Power & Utilities	Transitioning away from generation and renewable energy towards utility service provision, but beta estimates still likely to be overly influenced by non-comparable activities
CU CN Equity	Canadian Utilities Ltd-A	Although owns ATCO Australia, it has significant exposure to generation and renewables operations in Alberta
EMA CN Equity	Emera Inc	Owns generation activities in Nova Scotia and its pipeline activities are linked to the LNG market. However, it may be a useful comparator.
FTS CN Equity	Fortis Inc	Includes generation activities
H CN Equity	Hydro One Ltd	47% owned by Ontario government. However, entirely electricity transmission and distribution, so may be a useful comparator.
TRP CN Equity	TC Energy	Includes nuclear generation activities and gas storage
ENB CN Equity	Enbridge Inc	Exposure to commodity markets through transportation of crude oil and natural gas liquids.
Italy		
TRN MI Equity	Terna	Also the national transmission system operator and government influenced
SRG MI Equity	Snam	Includes gas storage and LNG operations, partially government owned
IG MI Equity	Italgas	Partial government ownership
United Kingdom		
CNA LN Equity	Centrica PLC	Mainly retail gas
NG/ LN Equity	National Grid PLC	Until recently (2024) it included system operation activities.
SSE LN Equity	SSE PLC	Generation and renewables activities
New Zealand		
VCT NZ Equity	Vector Ltd	Until recently (2025) held LPG wholesale/retail business and smart metering business
Spain		
ENG MC Equity	Enagas	System operation roles, owns LNG terminals and gas storage, hydrogen activities
RED MC Equity	Red Electrica	Transmission and system operation roles, 20% owned by government, recently sold its satellite and fibre operations
United States		

Ticker	Name	Reason for exclusion
AEE US Equity	Ameren Corporation	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, demand and competition risk. Reducing generation plant exposure but increasing energy trading exposure
AEP US Equity	American Electric Power	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operational, demand and competition risk
AES US Equity	AES Corp	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operational, demand and competition risk
ALE US Equity	Allete Inc	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operational, demand and competition risk
ATO US Equity	Atmos Energy Corp	Focus on methane gas distribution, pipeline and storage with no generation. Buys and sells gas so subject to demand and energy trading risk. Similar to stapled gas distribution and retail entities before separation
AVA US Equity	Avista Corp	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operational, demand and competition risk
BKH US Equity	Black Hills Corp	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operational, demand and competition risk
CMS US Equity	CMS Energy Corp	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operation, demand and competition risk
CNP US Equity	Centerpoint Energy Inc	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operation, demand, and competition risk
D US Equity	Dominion Energy Inc	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operation, demand and competition risk
DTE US Equity	DTE Energy Company	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operation, demand and competition risk
DUK US Equity	Duke Energy Corp	Vertically integrated energy utility operating in multiple jurisdictions, subject to extensive energy trading, generation plant operation, demand and competition risk
ED US Equity	Consolidated Edison Inc/	Vertically integrated New York based energy utility, subject to extensive energy trading, generation plant operational risk and competition subject to extensive energy trading, generation plant operation, demand and competition risk
EIX US Equity	Edison International	Vertically integrated energy utility owning Southern California Edison, operating across US and internationally, subject to extensive energy trading, generation plant operation, demand and competition risk
ES US Equity	Eversource Energy	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, generation plant operational

Ticker	Name	Reason for exclusion
		risk and competition subject to extensive energy trading, generation plant operation, demand and competition risk
ETR US Equity	Entergy Corp	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, generation plant operational risk and competition subject to extensive energy trading, plant operational (including nuclear operating and decommissioning), demand and competition risk
EVRG US Equity	Evergy Inc	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, generation plant operational risk and competition subject to extensive energy trading, generation plant operation, demand and competition risk
EXC US Equity	Exelon Corp	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, generation plant operational risk and competition subject to extensive energy trading, plant operation, demand and some competition risk
FE US Equity	First Energy Corp	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, generation plant operational risk and competition subject to extensive energy trading, plant operation, demand and competition risk
HE US Equity	Hawaiian Electric Industries	Vertically integrated energy utility holding company and public private partnership operating five separate power systems in Hawaii, subject to extensive energy trading, generation plant operation, demand and competition risk.
IDA US Equity	IDACorp Inc	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive upstream exploration, production energy trading, plant operational and competition risk. Subject to PBR by Hawaii PUC
KMI US Equity	Kinder Morgan Inc	Provides pipeline transportation and storage services for a wide range of energy products, not just natural gas. No cost-of-service regulation
LNT US Equity	Alliant Energy Corp	Vertically integrated energy utility holding company headquartered in Florida, subject to extensive energy trading, plant operation and competition risk
NEE US Equity	Nextera Energy Inc	Vertically integrated energy utility holding company, subject to extensive energy trading, plant operation and competition risk
NFG US Equity	National Fuel Gas Co	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive upstream exploration, production energy trading, plant operational and competition risk
NI US Equity	NiSource Inc	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational and competition risk
NJR US Equity	New Jersey Resources Corp	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
NWE US Equity	NorthWestern Energy Group Inc	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational and competition risk

Ticker	Name	Reason for exclusion
OGE US Equity	OGE Energy Corp	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational and competition risk
OGS US Equity	One Gas Inc	While it focuses on gas pipelines and is regulated, it is subject to competition from other IOUs
OKE US Equity	OneOK Inc	Not a statutory monopoly or subject to cost of service regulation by FERC or US public utilities commission
PCG US Equity	PG&E Corp	Vertically integrated energy utility holding company in California, subject to extensive energy trading, plant operational risk and competition
PEG US Equity	Public Service Enterprise Co	Vertically integrated energy utility holding company in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition from other IOUs
PNM US Equity	PNM Resources Inc	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
PNW US Equity	Pinnacle West Capital	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
POR US Equity	Portland General Electric Co	Vertically integrated energy utility, subject to extensive energy trading, plant operational risk and competition
PPL US Equity	PPL Corp	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
SJI US Equity	South Jersey Industries	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
SO US Equity	Southern Co	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
SR US Equity	Spire Inc	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
SRE US Equity	Sempra Energy	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
SWX US Equity	Southwest Gas Holdings Inc	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
WEC US Equity	WEC Energy Group Inc	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition
XEL US Equity	Xcel Energy Inc	Vertically integrated energy utility in multiple US jurisdictions, subject to extensive energy trading, plant operational risk and competition

Appendix E. Impact of NER on NSP exposure to systematic risk

This appendix details the impact of specific NER on NSP exposure to systematic (economy wide) risk. This is developed from an AER created table included in a 2016 AER rate of return decision, updated for any changes to the rules.[83]

Exclusive network operator licences issued by each jurisdiction	Statutes in each jurisdiction limit defined network operations to authorised network licence holders in each defined distribution licence area. As a result, licenced electricity and gas networks are protected from competition from potential entrants. The existence of network monopolies is the reason networks are subject to economic regulation.
6.2.6	The AER adopts a control mechanism formula to calculate the total revenue that service providers may collect over a regulatory control period (and for each year of a regulatory control period). This control mechanism automatically accounts for indexation and annual increases in efficient input costs. The control mechanism that the AER adopts (typically in the form of a revenue cap), also ensures a service provider has a guaranteed level of total revenue that it may collect across the regulatory control period, regardless of unexpected changes in demand. This significantly limits risks to revenue.
6.3.2(b)	The term of each regulatory control period is at least 5 years, providing a fixed duration in which a service provider has a regulated return on its assets, revenue certainty, and fixed terms of access for its services. Among other things, changes to the rate of return instrument have no effect until the following regulatory control period.
6.4.3(a)(1)-(3), 6.5.1, 6.5.2, 6.5.5, S6.2.1, S6.2.2B, S6.2.3,	The total revenue that the AER determines incorporates a return on and of the service provider's asset base. The historical asset base rolls forward from one regulatory control period to the next and from year to year within each regulatory control period. The NER guarantees recovery of historical asset costs through depreciation, the earning of a return on the asset base, indexation and recovery of future efficient capex. This substantially lessens risks in capital investment that might otherwise apply to a business operating in a workably competitive market. An asset that is not utilised or productive may still provide a return under the NER through the setting and rolling forward of the asset base, the return on and of the asset base and the application of indexation.

[83] See Table 3-3: Key clauses in the rules that mitigate systematic risk,' 3-27 *Attachment 3 – Rate of return; AusNet services distribution determination final decision 2016-20*, May 2016, AER

6.5.9	X factors in the control mechanism smooth revenues across the regulatory control period and limit shocks from the last year of a regulatory control period before the start of the next. The AER sets X factors, among other things, to allow service providers to recover a revenue shortfall in one year in a subsequent year. Through X factors, service providers have a stable and certain level of revenue over each regulatory control period, with reduced risks of short- term revenue volatility.
6.18	The prices service providers may charge annually are certain. They are set through a regulatory process to approve annual pricing proposals.
6.5.2	The AER sets the allowed (ex-ante) rate of return on the opening RAB. Previous references to the rate of return (ex-post) were removed in 2018. (Australian Energy Market Commission, Before 2018)
6.5.3	Provision for tax in determining total revenue is required for a benchmark entity, without regard to whether the service provider pays tax.
6.5.6 and 6.5.7	The AER assesses expenditure requirements for each service provider by reference to the amount necessary to meet a set of standards and objectives. These include the need to meet the expected demand for services and to meet quality, reliability, security, and safety standards. The AER does not assess expenditure by reference to the capacity of consumers to pay. This removes risks that could otherwise arise in providing a reliable and safe service. The AER reassesses the requirements of service providers for each regulatory control period to account for changes in market conditions and trends.
6.5.10	Allows service providers to pass through certain costs to consumers in circumstances where this might not be possible in a workably competitive market. For instance, the pass-through provisions provide for a pass through of costs that arise through regulatory change.
6.5.7(f), 6.6A, chapter 5	Establishes a planning regime for DNSPs that assists in predicting future costs and appropriate planning for changes in the commercial environment. This includes provision for contingent projects during a regulatory control period and longer-term projects through the RIT-D process.
6.6.5	Allows for the reopening of a determination for any material incremental capital expenditure following an unforeseen event beyond the reasonable control of the NSP. If approved, the Capital Expenditure Sharing Scheme (CESS) penalties for excess expenditure no longer apply. This clause is important in the context of substantial capital cost increases in major Priority Transmission Projects.
6.18.5	The pricing principles and accompanying network tariff reforms contributed to tariff rebalancing with a higher share of revenues from fixed connection charges, reducing inter-seasonal and inter-annual variability in revenues.

6.20, 6.21, 6.6.1(a1)(d), and RoLR provisions	Provides for a statutory billing and settlements framework with prudential requirements (and other similar provisions) to minimise financial risk associated with providing and charging for services. There is also provision for dealing with potential risks associated with retailer insolvency.

The National Energy Retail Law (NREL) and associated National Energy Retail Rules (NERR) regulate various aspects of commercial relationships between DNSPs, energy retailers and end customers. Under these arrangements:

- Customer hardship and related revenue recovery risks are borne by retailers not NSPs.
- NSP revenue from retailers is protected from retailer insolvency under the retailer of last resort (RoLR) scheme

Appendix F. Response to the AER's Questions

F.1 Overall priority issues for assessment

> 1. Are there other issues, beyond the weighted trailing average, equity beta and third-party yield curves stakeholders wish to raise? If yes, what are these and why do you consider they warrant consideration during the review?

Yes. We consider the AER should broaden the scope of this review to explore all opportunities for reducing the impact NSPs have on electricity and gas reticulation prices where this can be achieved without compromising incentives to invest. In particular, we recommend the AER broaden the scope of this review to cover the following issues.

- There is empirical evidence that the current specification of the real return on debt is overly favourable to equity investors. We consider the best and simplest way to deal with this issue would be to continue with the current method of calculating X factors and revenue within a regulatory period and then make a true-up to the RAB at the reset. The true-up would be based on a specification of the real return on debt so that it uses the applicable inflation rate for the year rather than the forecast inflation rate. This would ensure NSPs are compensated for the benchmark trailing average return on debt, no more or no less. See discussion from page 12.
- We have reviewed the AER's decision to set the term of the return on equity at 10 years rather than 5 years and have concluded that it was not based on evidence that a 5-year term would compromise incentives to invest. We do not consider the 10-year term is consistent with a reasonable interpretation of the NPV=0 condition or the Revenue and Pricing Principles. See discussion from page 44.
- We consider there is merit in making a RAB adjustment at each reset to true-up the difference between the return on equity over a regulatory period under the status quo and the return on equity had the risk-free rate been updated annually. This change would benefit consumers by limiting the price increases that occur when there are unexpectedly large inflation events. See discussion from page 46.

F.2 Equity beta

> 1. Do you agree with our preliminary options, as outlined in section 5.1.3? If no, why not? Are there any other potential options that you would like us to consider?

See section 4.2 on the comparator set of firms, where we propose a method for determining the equity beta/leverage combination.

2. How could we use the equity beta estimates of international energy firms to inform our decision on equity beta?

See section 4.3. Our finding is that there are only 3 firms that are relevant international comparators and even those do not appear to represent the systematic risk of NSPs.

3. What other filters and/or adjustments should we make to international energy firms and their equity beta estimates to make them more comparable to the equity beta estimates of Australian regulated energy networks, as outlined in section 5.1.2.1?

See section 4.3. We have identified only three international firms that we consider suitable comparators and even their risk profile is higher than Australian NSPs.

4. Do you have any suggestions on how best to address the leverage anomaly, as outlined in section 5.1.2.2?

See section 4.5. Assuming a 60% gearing is retained, we propose the use of a debt beta of 0.125 when converting raw equity beta data from the comparator set.

5. Do you have any suggestions on how best to address the issue of different domestic indices between Australian and international firms, as outlined in section 5.1.2.3?

See our statistical analysis in section 4.4 of the difference between Australian and international pure-play firms and analysis of the difference between countries. We propose to reduce the equity beta to 0.5 or below.

6. Other than the comparator set, do you have any comments on any other aspects of our approach to estimating equity beta?

The empirical analysis should be complemented by qualitative analysis of the risks associated with investing in Australian NSPs. See Appendix D and our discussion in section 4.1.

F.3 Weighted trailing average

1. Introduction of a weighted trailing average approach:

(a) Do you in principle support the introduction of some form of weighted trailing average (qualified by your answers to the later questions in this section)? Please include reasons.

We doubt there are strong reasons for introducing a weighted trailing average as it appears to make little difference and may increase prices for consumers. See section 2 for the issues we have with introducing a weighted TAPRD.

2. Application of the weighted trailing average approach:

(a) Should it apply to all network businesses by default, or only when forecast capital expenditure exceeds a certain threshold? Please include reasons.

If applied in a form similar to what we have modelled, we do not see why it could not be applied to all NSPs. The method is straightforward and just requires actual capex information to be available for the annual update. See section 3.2.

2 (b) If a threshold is preferred, what kind of threshold would work best (e.g. a percentage of RAB and/or a fixed dollar amount or some other measure/s), and what level would be appropriate for your suggested trigger/s? Please include reasons.

We do not consider a threshold is necessary. See section 3.2 for our proposed method should the AER decided to introduce a weighted TAPRD.

3. How the true-up mechanism should work:

(a) Do you support using a true-up to reduce the risk from capital expenditure forecasts? If you do or do not, please explain why.

The use of actual capex in the calculation of the weighted TAPRD would more accurately reflect financing requirements. See section 3.2 for our proposed method.

3 (b) What do you consider a preferred method of applying a true-up? Would it be through adjustments to the rate of return during the regulatory period (i.e. some form of rolling true-up), or through an adjustment to the rate of return in the next regulatory period (potentially at the time of the RAB roll forward calculations)? Why?

If a true-up is applied then any adjustment would be to correct the weighted TAPRD.

3 (c) If a rolling return based true-up with a two-year lag were adopted, are there specific implementation risks or modelling issues we should consider? Why?

If the AER decides to implement a weighted TAPRD, we have proposed a method of modelling the weighted TAPRD in section 3.20, which integrates with the existing annual update process.

4. Interaction with the CESS:

(a) Could financing benefits or losses be double-counted under both a true-up and the CESS? Why?

We have no comment.

4 (b) If so, should the CESS be amended after the Rate of Return Instrument is made to ensure it operates as intended?

We have no comment.

5. Reporting: (a) Are there any concerns with changes that might be needed to Regulatory Information Notices, the Roll-Forward Model, or the RORI?

We have no comment.

6. Costs: (a) Are there likely to be material incremental costs imposed on network businesses from applying a weighed trailing average to them (e.g. additional hedging or other financial transaction costs). If yes: what would these costs relate to (e.g. additional financial transactions of a given type); how large would you expect these to be; are these costs one-off or transitional; and what scheme design elements might reduce any incremental costs?

We have no comment as this is a matter for NSPs.

7. Transition: (a) What transitional arrangements or lead times would be necessary to help NSPs prepare for a change to a weighted trailing average?

Our proposed method included a way of dealing with existing debt. We do not consider any further transitional arrangements are required.

8. Overall design: (a) Does the proposed approach strike the right balance between incentive-based benchmark regulation and greater use of firm-specific cost information that may move the trailing average approach closer to cost-of-service regulation?

We consider our proposed method is consistent with the status quo because it is based on information already used in setting revenue for NSPs.

8 (b) Does the proposed approach strike the right balance between accuracy, simplicity and regulatory consistency? Why?

We consider it unlikely that a method more complex than what we have proposed is warranted.

8 (c) Would the use of a weighted trailing average add material regulatory burden and/or cost for NSPs to which it would apply? If yes, what are these likely to be?

No. It would simply involve an additional step in the annual update process, based on adding additional regulatory accounting information to the existing information.

8(d) Are there any other ideas or refinements we should consider? If yes, what are these?

Yes, our proposed method.

F.4 Third-party yield curves data

1. Do you support the reintroduction of the use of RBA yield curve data combined with Bloomberg or Refinitiv swap data? If no, why not?

We have not reviewed this proposal as we consider this is a technical matter that should not affect consumers.

2 Are there any concerns with the proposed method of calculating the return on debt in the absence of RBA spread to swap data (i.e. using swap rate data from another source)?

We have not reviewed this proposal.

About EMAS

Electricity Market Advisory Services is a bespoke consulting firm specialising in modelling electricity markets. While our focus is on the Western Australian wholesale electricity market, we also undertake financial modelling of electricity network and retail businesses. We have a range of models that can be used for financial analysis, simulations and forecasts.

Our services include:

- Dispatch modelling to assist in operating and investment planning processes;
- Curated data services, including demand simulation and intermittent generation output;
- Customised report generation;
- Modelling specific WEM processes including Relevant Level, Electricity Storage Resource Obligations, Individual Reserve Capacity Requirement, and Reserve Capacity Target/Prices; and
- Estimating and advising on rates of return for network businesses.

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