A Review of International Approaches to Regulated Rates of Return

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Notice

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Executive summary

This report reviews and summarises the approach to rate of return determination across eight regulators in six countries: Australia, Italy, the Netherlands, New Zealand, the UK, and the US.[1] We describe each regulator's approach to utility regulation, and compare the rate of return approach of each regulator to that of the AER. We also report a recent rate of return determined by each regulator, including the components of that rate of return, and make adjustments so that each determination is (so far as possible) comparable to a recent AER determination. Lastly, we identify key differences by comparing across the regulators and comment based on our view of best practices.

All regulators reviewed determine an authorised rate of return by estimating the cost of capital supplied by investors. Although there are differences across the jurisdictions we reviewed in the way that authorised revenues are determined, these differences do not create additional risks for investors that regulators provide compensation for in the authorised rate of return.

All regulators in our review determine the cost of equity using financial models that rely on capital market data. A common feature is that all use a group of comparators to determine the cost of equity for the utility subject to regulation. However, the regulators differ regarding the choice of financial models to use, the inputs to such models, the details of model implementation, and how to select a group of comparators. Approaches to the cost of debt vary more widely, from using the actual interest cost of the utility itself ("embedded cost of debt"), used by the US Federal Energy Regulatory Commission and the Surface Transportation Board), to a trailing average of historical market benchmark bond indexes (AER, ACM, Ofgem, Ofwat), or using the risk-free rate plus a debt premium (ARERA, NZCC).

When we compare the AER's method for estimating the cost of equity with that of other regulators, we find there are four key areas of difference. First, the AER does not incorporate forward-looking evidence into the cost of equity to the same extent as some other regulators. Second, the AER relies on the Capital Asset Pricing Model (CAPM) with some cross-checks, but places zero weight on the results of other financial models. In contrast, FERC and STB put equal weight on the CAPM and other models (notably including the dividend growth model), while Ofgem's checks against other benchmarks caused it to determine a cost of equity (slightly) above its CAPM estimate. Third, the AER reviews its rate of return methodology and determines most of the component parameters every four years, but does not implement changes in revenue determinations until the next control period starts for each utility. In contrast, most other regulators determine the rate of return and the revenue requirement

[1] The regulators are the Australian Energy Regulator (AER); the US Federal Energy Regulatory Commission and Surface Transportation Board (the FERC and STB); the ACM in the Netherlands; ARERA in Italy; the New Zealand Commerce Commission (NZCC); and Ofgem and Ofwat in Great Britain.

simultaneously, and therefore incorporate rate of return changes into revenues more quickly. Fourth, the AER relies on a longer estimation window when it measures equity beta from share price history than other regulators tend to use, and the AER also uses only Australian comparators. Other regulators tend to use a shorter window of 3-5 years, which means the estimates are better able to reflect current conditions. Regulators including ACM, ARERA, FERC, and NZCC incorporate some non-local comparators in their beta estimation.

I. Introduction

1. The Australian Energy Regulator (AER) has asked Brattle to compare the overall approach to rate of return used by the AER in Australia with that taken by regulators in other jurisdictions. In this report we describe the approach of the AER (Australia), the NZCC (the New Zealand Commerce Commission, which regulates energy networks and other infrastructure in New Zealand), Ofgem (the energy regulator in Great Britain), Ofwat (the water and wastewater regulator in England and Wales), the ACM (the regulator for energy networks and other infrastructure in the Netherlands), ARERA (the regulator for energy networks and other infrastructure in Italy), the FERC (the Federal Energy Regulatory Commission, which regulates interstate natural gas pipelines and electricity transmission in the US), and the STB (the Surface Transportation Board, which oversees the prices paid by certain railroad shippers in the US).

2. We describe the approach each regulator takes, and we also describe the overall framework for setting regulated prices or revenues—for which the rate of return is an input. After comparing the methodologies, we also describe one specific determination of an authorised rate of return made by each of the regulators. We show the rate of return that regulator authorised for use in a revenue determination, as well as the values of the component parameters that made up that authorised rate of return.

3. The rate of return authorised by one regulator is not necessarily directly comparable with that authorised by another regulator, for three key reasons. First, comparing one jurisdiction with another, there may be differences in the nature of the regulated entity and/or differences in the nature of the regulatory framework which give rise to different risk characteristics. Since the authorised rate of return compensates investors for bearing risk, different risk characteristics should give rise to different authorised rates of return, even if everything else were equal. Second, there are different "flavours" of rate of return. A 6% nominal vanilla rate of return is not the same as a 6% pre-tax real rate of return. When we compare rate of return determinations, we make adjustments where possible to bring the different determinations to a comparable basis. This addresses the second difference (the "flavours" of the rate of return). We do not adjust for differences in risk characteristics, because to do that would require data not typically presented in the regulators' determinations, but we comment on whether these differences are likely to be directionally increasing or decreasing the rate of return (relative to an AER determination). Third, the specific rate of return determinations were made at different dates, so financial market conditions may differ across the decisions.[2] We have not attempted to adjust for changes in financial market conditions (i.e., the date of the determination) because we consider that there is no reliable way to do this in a mechanical or formulaic fashion. For example, as we discuss below, while

[2] We note that there may be differences between the financial market conditions across countries as well as across time. We have not adjusted for that.

a change in the (spot) risk-free rate between two dates can be measured, we do not think that the overall rate of return changes one-for-one with the change in risk-free rate.

4. Nonetheless, we think that all of the regulators described in this report are determining an authorised rate of return based on an estimate of the cost of capital demanded by investors in the utilities they are regulating. Thus a comparison of methodologies and of authorised rates of return is meaningful.

5. After describing the different rate of return methodologies and comparing specific authorised rates of return, we identify those areas where there are significant differences among regulators. Where there are such differences, we explain which approach we prefer.

6. In this report we use the term "utility" to refer to the business, such as an electricity distribution businesses, which charges prices that are determined by the regulators we reviewed for this report. However, some utilities are not stand-alone corporations—they may be subsidiaries or operating divisions of a larger entity. Also, some utilities may provide both regulated and unregulated services. This can be a complicating factor in rate of return determinations: for example, it may not be possible to identify the relative proportions of equity and debt financing of a utility that is not a stand-alone corporation.

A. The "rate of return"

7. The "rate of return" is a component of cost-based prices. A typical formulation is for the regulator to determine a "revenue requirement", which is the sum of operating costs, depreciation, taxes and a return on investment. The return on investment is the "rate of return" multiplied by the "rate base"—the amount of capital that investors have put into the utility. Depreciation is the "return of" capital—it represents investors receiving back their original investment.[3] The regulator sets prices such that the utility is able to collect revenue equal to the revenue requirement. If the utility's costs are the same as the regulator's assumption when it determined the revenue requirement, then the residual—the excess of revenues over operating costs, depreciation and taxes—will be equal to the dollar amount of return on investment authorised by the regulator. If, further, there are no differences between rate base and the capital investors have put into the utility, then investors will receive a rate of return equal to the authorised rate of return.

8. Sometimes regulators set the "authorised revenues" directly: prices are then designed so that the revenue collected is equal to the authorised amount. If, at the

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[3] Conventionally, depreciation for regulatory purposes is on a "straight line" basis over the standardized life of an asset. For example, a utility asset costing $100 might be depreciated in 40 equal instalments of $2.50 over 40 years. Straight line depreciation is conventional and common in utility regulation. We explain below that some regulators, including the AER, adjust rate base for inflation. One way to think about the inflation adjustment is as a modification to the time-profile of depreciation (including, potentially, negative depreciation early in an asset's life).

end of the year, it turns out that the revenue collected is more or less than the authorised amount, there will be a "true up" in the next year to deal with this difference. Other regulators set "authorised prices", based on an expected quantity of services to be provided, so that the utility may collect more or less than the authorised revenue depending on whether the quantity of services provided turns out to be more or less than expected.

9. The utility's costs are likely to turn out to be different from the regulator's assumptions when it determined the revenue requirement.

10. Variances in revenues and costs (or the value of regulated assets) will result in the rate of return actually received by investors being different from the rate of return targeted by the regulator when it determined the revenue requirement.

11. The rate of return that investors expect from the regulatory framework must be at least equal to the opportunity cost of capital—the return that investors could (expect to) get from other investments with similar risk elsewhere. If this condition is not met, utilities would not be able to attract the capital that they need, because investors can invest elsewhere. Thus, regulators need to be able to estimate the cost of capital so that they can quantify the rate of return component of the revenue requirement.

12. This report is about how regulators set the rate of return—and therefore about how regulators estimate the cost of capital.

13. The cost of capital cannot be directly observed, but various models are available for estimating it. These models generally use market data as inputs:[4] specifically, the prices of securities (shares and debt) issued by utilities, as determined by trading in capital markets, as well as other related information such as analyst forecasts. Many utilities are subsidiaries or operating divisions of larger companies which also have other activities; and in some cases the parent company may not be a public company, and therefore not have actively traded securities with reliable prices. Thus regulators will usually estimate the cost of capital of a sample of "comparator" firms, with characteristics similar to the utility for which a rate of return must be determined.

14. Estimates of the cost of capital are inherently uncertain, yet at the end of the proceeding to determine authorised revenues, the regulator has to pick a single point estimate to use in calculating the revenue requirement.

B. Authorised and achieved rates of return

15. We explained above that the return investors expect from the regulatory framework must be at least equal to the opportunity cost of capital, in order that utilities can attract the investment they need. Utility assets—such as electricity transmission towers or natural gas pipelines—tend to last a long time. In addition, these assets

[4] There are accounting-based models, but there are not frequently used.

usually have no value except when used to provide utility service: they are sunk investments. These two features create a challenging situation for regulators and investors. Investors are making an essentially irreversible investment decision, relying on a commitment from regulators that regulators will set prices in such a way as to provide a reasonable rate of return over the life of the asset. Investors' expectations about future returns depend on whether regulators' commitment is credible or not—on whether regulators can credibly commit to providing a reasonable rate of return over the long term. If investors doubt that regulators will provide a reasonable return in the future, they may discount future returns, creating a "wedge" between the return that investors expect, and the return which regulators say that they will provide.

16. If there were a wedge between investor expectations and the returns regulators say that they will provide, this would be expensive for customers: investor expectations have to be at least equal to the opportunity cost of capital, as we explained above. Thus, if there were a wedge, regulators would have to set the authorised return *above* the cost of capital, in order that investors can expect to receive a return at least as great as the cost of capital. In consequence, utility regulatory frameworks are usually designed with strong protections to minimize the possibility that such a wedge might appear. For example, the legal duties of regulators are often set out in statutes, and regulators are often independent of the regular executive functions of governments. Another example is the "prudence" test used to determine whether capital expenditure should be eligible for continued inclusion in the rate base (and therefore earn a return and be recovered from customers over time). The prudence test asks whether a particular investment was reasonable at the time it was made, given what the utility knew (or ought to have known) at the time. The prudence test does not use hindsight. The prudence test would, for example, require (the cost of) assets to remain in the rate base and thus contribute to the return of and on capital after they are destroyed in a natural disaster—provided that the actions of the utility in operating and maintaining its system were prudent. Another example is the guaranteed recovery of electricity transmission assets, irrespective of usage.[5]

17. Since regulatory frameworks are usually designed to avoid a wedge between the cost of capital and the authorised rate of return, usually regulators do not have to consider setting the rate of return above the cost of capital. However, this could be necessary if there is uncertainty about the ability of the regulatory framework to permit the utility a reasonable opportunity to earn the authorised rate of return. This might happen, for example, if there is the prospect that changes in technology or some fundamental shift in the market might mean that the utility is unable to

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5 The FERC will pre-approve the recovery of 100% of abandoned electric transmission plant provided the plant was included in the local transmission organization's investment plan. (See Federal Energy Regulatory Commission, "Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act," Federal Register Vol. 85, April 2, 2020, para 82-84.)

charge the authorised price (because customers have cheaper competitive alternatives), causing utility assets to be stranded.

18. In the jurisdictions we review in this report, we are not aware of any examples of the regulator deliberately setting a rate of return above the cost of capital to address the risk of stranding assets (whether associated with competition or a lack of regulatory commitment).[6]

19. Most utilities operate under a form of "incentive" regulation, because regulators will usually not allow a utility to collect extra revenue in the future to compensate for costs being unexpectedly high (and hence returns unexpectedly low) in the past. Thus, a utility has a financial incentive to avoid unexpected cost increases. If a utility is able to reduce its costs below the level that the regulator anticipated when setting the revenue requirement and the authorised revenues, the utility may be able to earn a rate of return (the "achieved rate of return") that is greater than the authorised rate of return and greater than the cost of capital. Achieved returns above the authorised return when the utility is successful in controlling costs—and achieved returns below the authorised return when the utility is not successful in controlling costs—is an important part of how utility regulation works to encourage efficient operations.

20. Depending on the jurisdiction, some costs may be considered "outside the control of the utility" or "exogenous" and eligible for pass through treatment. Where this is the case, the utility has very little risk associated with this element of cost, because changes are passed on to customers. A common example is changes in local taxation (i.e., business rates or property tax). However, even if the treatment of such costs may vary from one jurisdiction to another, we would not expect this to have an impact either on the cost of capital demanded by investors in the utility, nor on the rate of return authorised by the regulator. We would expect that the relevant building block—opex, in the case of local taxes—would incorporate an unbiased estimate of the likely cost. Thus whether or not there is a pass through should not open up a wedge between the cost of capital and the authorised rate of return. Furthermore, we think it likely that most of these exogenous costs have little or no systematic risk,[7] so we would not expect an impact on the cost of capital either.[8]

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6 We explain below that the NZCC explicitly addresses the fact that estimating the cost of capital is uncertain, and that the NZCC sets the authorized rate of return above its mid-point estimate of the cost of capital. However, the reason it does so is because it considers that the adverse consequences of setting the authorized rate of return above the "true" cost of capital are less costly for customers than the adverse consequences of setting the authorized rate of return below the true cost of capital.

7 By "systematic risk" we mean correlated with the wider economy. We discuss this in more detail below when we introduce the Capital Asset Pricing Model. Financial risks such as those associated with Covid-19 affect financial markets across the globe albeit to a varying degree and appear to have a systematic effect.

8 We note that the FERC explicitly allowed the recovery of hurricane costs for both electric and gas transmission companies.

21. In addition to encouraging utilities to operate efficiently, sometimes regulators have other objectives that they wish utilities to achieve. For example, regulators in many jurisdictions require electricity distribution utilities to measure various aspects of service quality, such as the average number of power outages per customer per year. The regulator will set a performance target, and often will provide a financial incentive for the utility to perform at the target level: performance better than the target attracts a financial reward (i.e., an increase in authorised revenues), and performance worse than the target attracts a financial penalty in the form of a reduction in authorised revenues.

22. When performance incentives like this are part of the regulatory framework, they may be expressed in dollar terms or in terms of an increase or decrease in the authorised rate of return.[9] How the incentive is expressed makes no difference—what counts is the relationship between performance and financial outcome. In cases where a performance incentive is expressed as an increase or decrease in the authorised rate of return, this has nothing to do with the cost of capital, nor how the rate of return should be determined.

23. A performance based incentive should be symmetrical, in the sense that the expected payout under the incentive should be zero (after taking into account any relationship between performance and costs). If this were not so, expected returns would be biased up or down. This would complicate the regulator's task in setting the authorised rate of return relative to the estimated cost of capital.

24. We explained above that the achieved return could differ from the authorised return for various reasons, including: actual costs being different from the regulator's assumption when determining the revenue requirement; other performance incentives; or the quantity of services provided being different from the regulator's assumption. We also explained that investors' expected return needs to be at least equal to the cost of capital. Although the regulator conventionally "builds up" the revenue requirement by adding together estimates of opex, depreciation, tax and a return on rate base (the "building blocks" of the revenue requirement), investors care only about the returns they receive, irrespective of how the dollars comprising those returns are described by the regulator. Investors' returns are the net when actual expenses and actual tax are subtracted from actual revenues. Therefore, if in setting the revenue requirement, a regulator anticipated opex of $100m, but actually allowed only $99m for some reason, while setting all the other building blocks correctly, investors would expect returns $1m less than if the regulator had set the opex building block correctly. The regulator could "correct" for this by increasing the rate of return to deliver the "missing" $1m.[10]

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9 Suppose that the interruptions target is 5 interruptions per customer per year, and that a score of 6 or more attracts a penalty of $10m (and a score of 4 or better attracts a reward of $10m). These figures could be "converted" into rate of return units by dividing the $10m by the value of the rate base. So if the rate base was $1,000m, the incentive would be +/- 1% on the rate of return.

10 While the end result is the same in the example provided, the inclusion of a cost component in a different bucket than where it was incurred reduces transparency.

25. Of course, in the situation described above, it is strange for the regulator to under-estimate one building block and over-estimate another. It would be simpler and more transparent simply to use unbiased estimates for all of the building blocks. Nonetheless, we think it is important to recognize the potential for this outcome to occur. In many jurisdictions, the outcome of a regulatory determination has implicit trade-offs. For example, in deciding how to respond to a regulator's draft decision, or in deciding whether to launch an appeal,[11] a utility or a customer group may consider the decision "in the round". For example, if the utility considers that the opex allowance is unreasonably low, but that the tax building block is generous, it may not be worth appealing the regulator's decision.

26. We are not aware of any regulator that has explicitly set the authorised rate of return above or below the estimate of the cost of capital in order to "correct" for an over- or under-estimate of one of the other building blocks of the revenue requirement.[12] However, as we describe below, Ofgem is currently proposing to set its authorized return on equity 0.5% below its estimate of the cost of equity in an upcoming determination because of anticipated "out performance" in other areas of the revenue requirement determination. We would regard any incentive mechanism that gave rise to "anticipated out performance" as being asymmetrical, and we would recommend adjusting the incentive scheme rather than the rate of return. In our analysis below we remove Ofgem's proposed adjustment to the authorized return on equity (i.e., we focus on Ofgem's estimate of the cost of equity).

27. It is possible that there are other similar adjustments which are implicit rather than explicit. This would of course make comparisons across jurisdictions more difficult. We have not seen any examples of the authorised return explicitly set higher than the cost of capital to compensate for stranding risk or for an under-estimate in one of the other building blocks. We think it unlikely that regulators are doing this implicitly.[13] Therefore we think that it is reasonable to equate the regulator's authorised rate of return with the regulator's view of the cost of capital and the regulator's view of the returns investors expect.

28. Nonetheless, we have considered the possibility that there could be a utility for which investors effectively discount the regulator's authorised rate of return, either because they anticipate that future market changes might introduce competition,

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11 We are not aware of any jurisdictions where the regulator's revenue determination cannot be appealed, though the scope of appeal rights varies widely.

12 The issue as to whether the authorized return is higher or lower than the cost of capital was the subject of a workshop before the California Public Utilities Commission in 2016, which subsequently was not acted upon. Source: CPUC, "Moving Toward Value in Utility Compensation," June 13, 2016; materials available at https://www.cpuc.ca.gov/General.aspx?id=10745.

13 We note that the FERC explicitly allows for certain transmission ROE incentives (e.g., for having its transmission assets included in a regional transmission organization). Such incentives are removed from the data discussed below.

making it impossible to collect the authorised revenue, or because they fear that the regulator will "disallow" some investment as imprudent or inefficient, or the regulator will under-estimate one of the other building blocks. For this utility, the regulator would have to set the authorised rate of return above the cost of capital, as outlined above. However, we do not think that the cost of capital itself will change. This is because the risk of stranding or disallowance in most instances is diversifiable.[14]

29. In New Zealand, the NZCC does explicitly set the rate of return higher than its mid-point estimate of the cost of capital, although it does this for a different reason than that discussed above. The NZCC recognises that all estimates of the cost of capital are inherently uncertain, and considers that the adverse impacts of setting the rate of return too low (relative to the "true" cost of capital) are likely to be worse than the adverse impacts of setting the rate of return too high. The NZCC therefore sets the rate of return above its mid-point estimate of the cost of capital.[15]

30. We noted above that one way to think about the rate of return is that investors need to be able to anticipate returns at least equal to the opportunity cost of capital in order that the utility can undertake necessary investment. Recognising that the objective is to ensure that utilities can access capital markets when needed, sometimes regulators also look at the type of cash flow metrics that credit analysts typically examine, under the heading of "financeability". However, to the extent that this analysis reveals a potential problem, regulators mostly seek to address it using "NPV-neutral" mechanisms which are not related to the cost of capital and which do not involve modifying the authorised rate of return. For example, the AER considers that financeability and associate cash-flow metrics are not relevant factors for setting the rate of return,[16] and Ofgem and Ofwat use measures such as changing depreciation rates to improve cash-flow metrics.[17] Increasing the depreciation rate means that investors recover the principal amount of their investment more quickly, and therefore the cash flow position of the utility is improved. However, in the calculation of the revenue requirement, the rate of return component is unchanged.[18] The FERC similarly will consider varying

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14 And, as discussed above, instances of stranding are rare. For example, if market changes cause stranding, regulators may allow uncollected revenues to be tracked in a deferral account for future recovery, or other changes to reduce or eliminate failure to recover. These adjustments to reduce stranding are preferable to a change in the allowed return to compensate for it.

15 NZCC, Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services Reasons paper, October 30, 2014, p. 15.

16 Rate of Return Instrument, Explanatory Statement, p. 405.

17 See, for example, RIIO-II – Finance, paragraph 4.64.

18 The dollar amount of returns will be lower over time if depreciation rates increase: as the principal amount is recovered more quickly, the outstanding dollar amount of investment is lower at any point in time, so for a given *rate* of return, the dollar amount of return is lower. Increasing the

depreciation rates or guaranteeing the recovery of certain investment prior to the utility undertaking the investment.

31. In circumstances where a utility is undertaking a very large investment program, there may be financeability concerns associated with the impact on the investment program on cash flows, and there may also be concerns that the risks associated with the expansion and the new assets may be different from those of the associated with the rest of the utility's operations. The latter could potentially indicate an impact on the cost of capital, and hence the required rate of return. We are aware of some examples where regulators have applied an uplift to their rate of return decision because of the impact of large expansions on risk, but this does not seem to be a current issue for any of the regulators we have reviewed for this report.[19]

C. Different "flavours" of the rate of return

32. Any regulatory decision on a rate of return is ultimately used to calculate a "revenue requirement"—the total cost of owning and operating a pipeline or network or other utility business. This total cost includes the opportunity cost of the capital employed. Utilities are funded through a mixture of debt and equity investment, and the relevant opportunity cost of capital is a weighted average of the cost of debt and the cost of equity.

33. The opportunity cost of capital provides compensation for, among other things, the fact that the value of money tends to decline over time (i.e., the fact that there is inflation). A $100 loan that attracts interest of 3.5% for a year does so, in part, because when the loan is repaid at the end of the year the $100 will be worth less—will be exchangeable for a smaller quantity of goods—than at the start of the year.

34. In some jurisdictions, the government (and some corporate borrowers) issues "inflation-protected" or "inflation-linked" debt. Like regular debt, these securities pay periodic interest according to the coupon rate. Unlike regular debt, the principal of the bond is not a fixed amount, but is rather indexed to inflation. $100 of a one year inflation-linked bond pays interest and, at the end of the term, will repay $100 plus the change in the inflation index. If inflation is expected to be positive, investors holding the inflation-linked bond receive not only interest payments but also growth of the principal. Thus, the interest rate on inflation-linked debt will be below that on equivalent regular debt.

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depreciation rate brings forward cash flows in time, but does not change the net present value of the cash flows (when they are discounted at the rate of return).

19 For example, Ofgem moved to the top of its cost of equity estimates for the Scottish electricity transmission companies in the RIIO-T1 price control, because of the size of the investment program relative to the asset base (see *Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues*, Ofgem (31 March 2011)).

35. In some jurisdictions, utility investors receive a return on their investment in the form of current earnings only. Operating expenses and depreciation are deducted from revenues and, after paying tax, the balance is the return available to investors. In other jurisdictions, utility investors receive this return, but also have an additional benefit: an inflation adjustment of the rate base. In North American jurisdictions, the rate base is not adjusted for inflation,[20] so the return investors receive is purely earnings minus tax. In these jurisdictions, therefore, the return on investment should be set equal to the expected after tax cost of capital. However, in jurisdictions which do adjust the rate base for inflation, there would be a double-counting if investors' investment increased with inflation and at the same time the investors earned the opportunity cost of capital in current earnings. In these jurisdictions, the regulator will set the rate of return equal to the opportunity cost of capital less inflation—or, in other words, these regulators will target a "real" rate of return, rather than a nominal rate of return.

36. In comparing rate of return decisions across jurisdictions, therefore, we need to be clear about whether the rate of return is the only compensation provided to investors, or whether they also receive an additional "write up" of the ratebase.

37. The opportunity cost of capital is the return demanded by investors. If that cost of capital is 8%, then the utility should be able to pay its investors a return of 8% per year and therefore needs to collect sufficient revenue so that the residual, after expenses and depreciation is 8%. Clearly, one of the expenses the utility must pay before returning the 8% to its investors is corporate taxes.

38. When the regulator calculates the revenue requirement, in some jurisdictions the overall rate of return is "grossed up" for tax. In this case, the revenue requirement is equal to: opex + depreciation + rate base x (rate of return) x $1/(1 - T_c)$ where T_c is the tax rate. In this case, the "rate of return" is the weighted average of the cost of equity and the "post-tax" cost of debt (known as the after-tax weighted average cost of capital (or ATWACC)). The post-tax cost of debt is less than the rate of interest demanded by lenders because, in most jurisdictions, interest expense is deducted from income before tax is paid. Therefore, in jurisdictions where the regulator "grosses up" for tax,[21] the regulator will target the ATWACC as the rate of return. This rate is also often called the "post tax WACC". The post-tax WACC is <u>not</u> the utility's cost of capital, in the sense that it is not the return that investors demand. It is the return which, when grossed up for tax, provides the utility with sufficient pre-tax income to pay tax and to pay investors the return they demand. The return investors receive will not be equal to the post-tax WACC (because the whole of the

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20 An exception is FERC-regulated liquids pipelines, which are regulated under a sector-specific statute. The regulatory framework for liquids pipelines is different from the frameworks for natural gas pipelines and electricity transmission that we describe in this report (albeit the regulator for all three sectors is the FERC).

21 The cost of debt needs to be adjusted for the value of the tax shield that arises from being able to deduct interest expenses before paying tax. In some cases, this is done in a separate line item or in the estimation of the tax amount.

post-tax WACC is grossed up for tax, but the utility will only pay tax on the equity return portion).

39. In some jurisdictions, the regulator grosses up for tax as described above, but, when calculating the revenue requirement, by convention does not show the tax gross-up as a separate step, but rather combines it into the rate of return. In these jurisdictions, therefore, the rate of return is ATWAC x $1/(1 - T_c)$—conventionally called the "pre-tax WACC". The revenue requirement is then opex + depreciation + rate base x (rate of return). As with the post-tax WACC, the pre-tax WACC is not the cost of capital and is not the return which investors demand.

40. Finally, in still other jurisdictions, the regulator decides that simply "grossing up" the after tax return for corporate taxes is insufficiently precise as a way of estimating the utility's tax expense.[22] For example, the amount of depreciation that can be deducted from income before (current) tax is paid will often be different from the amount of depreciation recorded in financial and regulatory accounts. The latter is the amount the regulator includes in its calculation of the revenue requirement. Because of this mis-match, the regulator may conclude that simply "grossing up" for taxes is not precise enough. Rather than "grossing up" for tax, the regulator may forecast the tax expense directly. In this case, since the regulator knows the authorised cost of debt and the authorised capital structure, the forecast of tax paid will already reflect the tax shield on debt. Therefore the revenue requirement is opex + depreciation + tax + rate base x (rate of return). The "rate of return" in this case is the weighted average of the cost of debt and the cost of equity, sometimes to avoid confusion called the weighted average of the pre-tax cost of debt and the post-tax cost of equity, or "vanilla WACC" for short.

41. The rate of return targeted by a particular regulator can thus be one of the following "flavours":

a. real vanilla WACC

b. nominal vanilla WACC

c. real pre-tax WACC

d. nominal pre-tax WACC

e. real ATWACC

f. nominal ATWACC

42. In each case, of course, the choice of which rate of return to use is determined by how the revenue requirement is calculated, and whether the rate base is written up for inflation or not.

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22 Some jurisdictions estimate the taxes paid to tax authorities, while others estimate the tax obligation the income gives rise to regardless of the timing of the actual payment.

43. A further complication is that in some jurisdictions, including Australia and New Zealand, the rate of return that a company needs to offer its investors is influenced by the *investors'* taxation. The tax systems of these countries permit investors to deduct from their tax liability any tax deemed to have been paid at the corporate level on dividends the investor has received. A dividend payment is "franked" to show that corporate income tax has been paid, and this becomes a "franking credit" that can be set against the investor's income tax liability. The existence of franking credits reduces the return that a company must pay to its equity investors to attract investment, since the investors additional receive an extra return in the form of a tax credit or refund.

44. The AER takes into account the value of franking credits by reducing the tax building block (in effect, the AER estimates how much of the tax that will be paid by the utility will then be claimed back by investors, and removes that amount from the tax building block). An alternative would be to adjust the cost of equity rather than the tax building block, but the AER's approach has the benefit of facilitating comparisons with other jurisdictions. The AER's approach means that the cost of equity it uses represents the total return demanded by equity investors, and the AER includes all of that return in its calculation of the vanilla WACC. However, Australian equity investors do not expect to receive all of their demanded equity return from the companies they invest in—some of it comes from the tax system as a reduction in their income tax (the franking credits). There is no double-counting in the AER's method because the value of the franking credits is deducted from the tax building block.

45. The NZCC, in contrast, does adjust the cost of equity. Thus, the NZCC's cost of equity does not represent the return that equity investors in New Zealand demand (it represents that portion of their return which comes in dividends and capital gains, but it does not include the portion of the equity return that comes via the taxation system).

46. We discuss below whether and how it is possible to make meaningful comparisons between jurisdictions that use different flavours of the rate of return.

D. Methods for determining the rate of return

47. Since there are many common features among the approaches taken by the different regulators, we introduce some of them here. In particular, all the regulators determine a cost of equity and a cost of debt, with the overall rate of return being a weighted average of the two. The cost of equity is the return that must be provided to shareholders to induce them to supply equity capital, and the cost of debt is the return that must be provided to lenders to induce them to lend.

48. Regulators determine the cost of debt as either the interest rate actually paid by the individual utility (often called the "embedded debt" approach),[23] or they will estimate a benchmark cost of debt using the results of an index or sample of corporate bonds over a historical period.[24] The cost of equity can be estimated using a variety of models. The most common across the regulators reviewed in this report is the Capital Asset Pricing Model (CAPM), which we introduce here. The other models are less common and we describe them below in the sections dealing with the regulators that use them.

49. The CAPM regards the cost of equity as being made up of the risk-free rate of return plus an equity premium. The risk-free rate of return is simply the return available from investing in government bonds. The equity premium is calculated as the market risk premium (MRP) multiplied by a parameter called "equity beta". The MRP is the additional return, above the risk free rate, that investors can earn by investing in a diversified portfolio of risky assets. Conventionally the MRP is interpreted as the difference between the return expected from holding a diversified portfolio of shares, and the risk free rate. The equity beta parameter represents the relative riskiness of a specific risky investment (i.e., the equity of the utility in question) compared to the market as a whole.[25] The equity beta is estimated by measuring the degree to which returns from owning the equity of the utility are correlated with returns from owning the market portfolio. Returns from holding equity and the market portfolio can be calculated from a time series of share prices.

50. Since there is a good deal of noise and estimation error in measuring equity beta (and because the equity in many regulated utilities is not listed on public markets), typically analysts will select a number of firms that are comparable to the utility in question, and measure equity beta using those firms.

51. There are many varieties of the CAPM, and different ways for estimating the risk-free rate, MRP and equity beta. Thus, although all of the regulators we review use the CAPM, there are important differences among them.

E. Our report

52. The remainder of our report compares the AER's current approach with other regulators' approaches to the determination of the rate of return for regulated

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23 Some regulators (e.g., Ofgem and Ofwat) use the term "embedded debt" to refer to existing debt on which Ofgem and Ofwat allow a historical benchmark return. In contrast, when US regulators refer to "embedded debt" they allow the *actual* interest expense on this debt. In this report when we refer to "embedded debt" we mean the latter concept.

24 The AER and other regulators use a ten-year averaging period, which can be thought of as assuming that the utility issues ten-year bonds and refinances 10% of its debt each year. An alternative "on the day" approach effectively assumes that the utility's debt can be refinanced as at the start of each regulatory period. The "on the day" approach is not often used.

25 Technically, the equity beta measures systematic risk or risk that investors cannot eliminate through diversification.

entities. We discuss the approaches of seven jurisdictions in addition to the AER: the Dutch Authority for Consumers and Markets (ACM), the US Federal Energy Regulatory Commission (FERC), the US Surface Transportation Board (STB), the Italian Regulatory Authority for Energy, Networks and the Environment (ARERA), the New Zealand Competition Commission (NZCC), and two UK regulators Ofgem (regulates electric and gas utilities) and Ofwat (regulates water utilities). We first review and compare the approaches, and then we compare the results of each approach by examining a specific rate of return decision for each regulator. The appendix contains a detailed description of each methodology.

II. The AER's current approach versus international approaches

A. Our review process

53. The AER asked us to review how international utility regulators set the authorised rate of return in their jurisdictions. Additionally, we were asked to compare each approach to that of AER and to provide a critical evaluation of the approaches taken by the international regulators.

54. For each jurisdiction, we summarize the regulator's objective and overall approach to determining the authorised rate of return. We review the regulator's approach to determining the cost of equity, the cost of debt, and capital structure. In doing so, we discuss the nature of the target rate of return: nominal vanilla WACC, real pre-tax WACC or some other target; the method or methods used to determine the cost of equity and the inputs to these models; the methods used to determine the cost of debt; the approach to determining gearing, and the treatment of taxes (including imputation credits if applicable).

55. We have a detailed description of the method used in each jurisdiction in the appendix. Each write up also contains the results of one recent rate of return decision.

56. The main body of our report draws on the detailed descriptions in the appendix. Citations to the source material we reviewed and on which we rely for the factual information about each regulator's rate of return methodology are in the appendix.

57. In section II.B we summarise the structure of the industry and the regulated utilities to provide context for the discussion of the regulatory framework that follows. In section II.C we describe each regulator's overall objective, the framework for determining authorised revenues, and the overall approach to rate of return within that framework. We compare each jurisdiction with the AER to highlight similarities and differences in overall approach. Then in section II.D we examine the components of the rate of return methodologies in more detail, and compare across jurisdictions to identify common themes and key differences. Finally, in section II.E we take one specific rate of return decision from each jurisdiction and show these authorised rates of return, and their component parameters, on a comparable basis across jurisdictions.

B. The industry context

58. Across the jurisdictions we reviewed, there are some differences in the structure and ownership of the regulated utilities. We summarise these differences in Table 1.

Table 1

			AER	ACM	FERC	STB	ARERA	NZCC	Ofgem	Ofwat
[1]	Approximate number of utilities regulated		~30	10	50[+]	5-10	200+	~25	~25	~25
[2]	Sectors regulated	Electricity transmission	✓	✓	✓		✓	✓	✓	
		Electricity distribution	✓	✓			✓	✓	✓	
		Gas transmission	✓	✓	✓		✓	✓	✓	
		Gas distribution	✓	✓			✓	✓	✓	
		Water								✓
		Waste-water								✓
		Rail networks				✓				
[3]	Are utilities investor owned?		Mostly	Mostly not	Yes	Yes	Some	Yes[++]	Yes	Yes
[4]	Vertical separation of utility infrastructure (in practice)?		Mostly	Yes	No	No	Mostly[++++]	Mostly	Mostly	NA
[5]	Stand-alone control for infrastructure only		✓	✓	✓	✓	✓	✓	✓	[+++]

Notes:

[+] FERC rate of return methodology is usually not revisited in indiviudual determinations; methodology can be reviewed in separate proceding.

[++] Some distribution utilities are customer-owned but their prices are not regulated by the NZCC.

[+++] Water companies regulated by Ofwat also perform the retail function.

[++++] Utilities are subject to company unbundling requirements, but not to ownership unbundling requirements. In practice while gas is mostly separated, the largest electricity group has companies operating in the generation, distribution and retail markets.

[4]: This row indicates whether the pipes/wires companies are separate from retail and generation and gas shippers.

59. In terms of scope, most of the regulators we reviewed cover gas and electricity distribution, gas transmission pipelines, and electricity transmission.[26] However, the STB regulates railroads, and Ofwat regulates water and wastewater services, and neither has any responsibility for energy infrastructure. The FERC regulates gas transmission and electricity transmission, but does not regulate gas or electricity distribution (this is the responsibility of individual state regulators). Half of the regulators in Table 1 regulate about 25 utilities, the others more or fewer, but usually either several utilities have their revenue determinations in parallel, or the regulator will implement an established methodology for each individual utility but will not re-open the design of the methodology for each utility. Thus each regulator's rate of return methodology tends to be quite stable over a period of years.

60. The ownership of the gas and electricity sectors is similar across most jurisdictions. In most jurisdictions, most or all utilities are owned by private investors. The Netherlands is an exception, although we understand that the ACM ignores the government ownership of the utilities when determining the rate of return.[27]

61. The structure of the industry is also similar. Vertical separation (for example, between transmission and generation, or between distribution and retail) is not always a legal requirement, but generally there is little vertical integration. Vertical integration is perhaps most common in the US, although this issue is not a

[26] Some of the regulators also regulate other sectors. For example, the NZCC also regulates airports, and the FERC also regulates liquids pipelines (but under a different legal framework).

[27] This is consistent with the financial economics premise that the cost of capital depends on the risk of the assets.

consideration for the FERC for determining the rate of return of a specific (electric or gas transmission) utility, because FERC determines prices only for that particular function. [28] In particular, all of the jurisdictions have stand-alone revenue determinations and separate regulatory accounts for each of gas distribution, gas transmission, electricity transmission and electricity distribution.

C. Overall regulatory framework and rate of return methodology

62. In this section we look at the overall regulatory framework in the different jurisdictions, and the rate of return methodologies within that overall framework. In Table 2 we summarise the overall objective of the regulator and we describe some of the key features of the regulatory framework and the rate of return methodology.

63. Next, we describe our understanding of the AER's regulatory framework, and then we compare the key features of each jurisdiction with those of the AER.

[28] There may well be a practical significance, in that where many utilities are part of a larger corporate group rather than being stand-alone entities, it may be difficult to find a set of comparable companies for which capital market data is available and which are reasonable benchmarks for a regulated utility.

Table 2

		AER	ACM	FERC	STB	ARERA	NZCC	Ofgem	Ofwat
[1]	High-level legal objective	Efficiency / consumer interest	Efficiency	Just and reasonable rates	Reasonable max rate where no competitive alternative	Efficiency / competition / consumer interest	Consumer interest / promote competition	Consumer interest / promote competition	Consumer interest / promote competition
[2]	Form of regulatory control — Revenue cap	✓	✓			✓	✓	✓	✓
	Price cap			✓					
	Other				✓				
[3]	Rate of return proceeding separate from revenue determination?	Yes	No	Sometimes+	Yes	Yes	Yes	No	No
[4]	Length of control period (years)	5	5	varies*	1**	6	5	5	5
[5]	Years between rate of return proceedings	4	NA	NA	1	3/6Δ	7ΔΔ	NA	NA
[6]	Rate of return framework	Real vanilla WACC CAPM r_e; trailing average r_d	Real pre-tax WACC CAPM r_e; trailing average/ forecast r_d	Determine r_e r_e based on various models; embedded r_d	Nominal vanilla WACC r_e based on various models; embedded r_d	Real pre-tax WACC r_e based on a variant of CAMP; r_d is r_f plus a premium	Real vanilla WACC r_e based on a variant of CAPM; r_d is r_f plus a premium	Real vanilla WACC CAPM r_e with an uplift; trailing average r_d	Real vanilla WACC CAPM r_e; trailing average r_d
[7]	Components of the rate of return that are updated during the control period	r_d is updated annually; r_f determined at the beginning of control period	No updating after the control period starts	NA	Annually updated	Results of rate of return proceeding flow through immediately into revenues	r_d and r_f determined at the beginning of control period, no updating	r_f and r_d updated annually	r_d updated annually***

Notes:

* FERC price determinations are evergreen, until the utility or customers (or FERC itself) requests a new determination.

** STB determines the rate of return annually, although these determinations do not automatically flow through into rates.

*** While Ofwat does not update the cost of debt annually, it has indicated that the cost of debt would get trued up at the end of the control period.

\+ FERC rate of return methodology is usually not revisited in indiviudual revenue determinations; methodology can be reviewed in a separate proceding; for ISO/RTOs with multiple transmission owner members, FERC determines ROE only, not revenue requirements.

Δ Inflation, MRP and risk-free rate are updated every 3 years, with the overal rate of return re-determined every 6 years.

ΔΔ Parameters and methodology must be reviewed at least every 7 years.

1. The AER

64. The AER's overarching objective is to contribute to achieving the "National Electricity Objective" and "National Gas Objective": "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system." and "to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."[29] In Table 2 we summarise this as an "efficiency" objective, for the purpose of comparison with other jurisdictions.

65. The AER determines the revenues for electricity distribution and gas distribution networks, for electricity transmission networks, and for some natural gas transmission pipelines.[30] Most utilities in Australia are investor-owned, but the AER ignores ownership when determining the rate of return.

66. The AER generally determines a revenue cap for each of the utilities it regulates—meaning that the utility can collect the revenue that the AER authorises, independent of whether the quantity of services provided turns out to be higher or lower than expected in each year.[31] Although each utility has its own proceeding to determine authorised revenues, that proceeding does not address rate of return *methodology*, which is instead addressed in a separate proceeding. The determined rate of return methodology applies to all subsequent revenue determinations.[32]

67. The revenue determination for each utility lasts five years, while the rate of return methodology must be re-determined every four years.

68. The regulatory framework requires the AER to include all actual capital expenditure in the rate base (and therefore to provide a return on and of this investment), provided that the capital expenditure in the prior regulatory period was less than that approved by the AER at the start of that prior period. Capital expenditure above the previously-approved level can be excluded from the rate base if the AER considers that the extra investment was not efficient. The other jurisdictions have different approaches. For example, the NZCC has to include all

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29 National Electricity Law, cl. 7; National Gas Law, cl. 23. See also "National Energy Objectives" at https://www.aemc.gov.au/regulation/regulation

30 The AER does not regulate utilities in Western Australia.

31 We understand that the framework does not require a revenue cap and that some utilities used to be under a price cap, but that almost all are now under a revenue cap.

32 The legal framework permits the AER to determine a separate rate of return methodology for gas and electricity utilities, but does not require this. Currently the same methodology applies to both sectors.

actual investment in the rate base, without an efficiency test,[33] whether or not the forecast is exceeded; Ofgem can exclude capex for efficiency even if the prior forecast was not exceeded. The FERC frequently pre-approves capital expenditures for electric transmission and guarantees that investment up to the approved amount will go into the rate base.[34] We do not consider these variations to be significant in relation to the rate of return, for two reasons. First, "disallowances" are in any case rare. We are not aware of any significant examples, and, as discussed above, there are good reasons for regulators to support investor expectations of recovery. Second, we do not observe any regulators determining an authorized rate of return higher than the regulator's assessment of the cost of capital.[35] As discussed above, such a wedge could be seen if investors anticipate not recovering some of their capital. We would also not expect differences across the reviewed regulators to have an impact on the cost of capital itself, because disallowances generally would not be a systematic risk.[36]

69. We observe some differences in the degree to which utilities are exposed to various cost and revenue risks (including the extent of pass throughs for exogenous shocks, and the length of the regulatory period itself).[37] For example, the AER may give pass-through treatment for changes in property taxes, whereas Ofwat does not currently allow a pass-through treatment for the equivalent charges. We would not expect these differences to be significant for determining the rate of return, because these are unlikely to be systematic risks.

70. Although the AER determines a nominal vanilla WACC, the mechanics for calculating authorised returns are such that the revenues collected are adjusted for actual out-turn inflation, and the regulated asset base at the start of each five year period is adjusted for actual inflation over the prior period. We therefore characterise the AER's approach as targeting a real vanilla WACC (calculated as a

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33 *Setting the customized price-quality path for Orion New Zealand Limited Final reasons paper*, NZCC (29 November 2013), paragraph B10.1

34 See, for example, FERC, "Order No. 679," 2007.

35 The NZCC authorises a rate of return above the mid-point of its cost of capital estimate, but for different reasons.

36 If a regulator were to frequently disallow capital expenditures, we would expect the utility (and its investors) to be cautious about further investments. Bondholders, especially those backed by the potentially non-recoverable assets, might demand a higher yield (in effect, to compensate them for the risk of non-recovery, similar to a default risk). However, the higher yield does not imply a higher cost of debt or a higher overall cost of capital. The higher yield is an increased return *if there is no default*. The yield multiplied by (1 minus default risk), which is the expected return, will stay the same.

37 Other things equal, a longer regulatory period would be associated with more variation in achieved returns, because there is a longer period of time for actual costs to diverge from the levels forecast at the start of the control period. The variation in return will be reduced if costs are fully or partially updated within the control period.

nominal vanilla WACC less expected inflation, determined at the start of the control period and not updated).

71. The AER's overall approach to rate of return is to use the CAPM to determine the cost of equity, and to estimate a cost of debt equal to a historical average of a benchmark corporate bond index. This methodology was determined in the 2018 "Rate of Return Instrument", which sets out a) the values of certain parameters used to calculate the cost of equity and b) a prescriptive methodology for estimating other parameters. The parameters in a) will be used in every revenue determination until the Rate of Return Instrument is next redetermined (in 2022), and the methodologies in b) will similarly be used in every revenue determination.

72. The parameters, which do not change, are the MRP, equity beta and gearing.[38] In contrast, the figure for the risk free rate is not determined in the Rate of Return Instrument, but rather a method is specified for determining it. Thus, when each revenue determination is due, the AER will apply the method for determining the risk free rate, using contemporaneous data at that time. Similarly, the method for determining the cost of debt is set out in the Rate of Return Instrument, so again the cost of debt will reflect current market data at the time of the revenue determination.[39]

73. Hence, as each revenue determination is due to be decided over the 2018–2022 period, the cost of debt will be determined at the time of the determination, while the cost of equity will be determined using a contemporaneous estimate of the risk free rate, together with the MRP and equity beta determined in 2018. The overall rate of return will be the weighted average of the cost of debt and cost of equity—with the weight (gearing) also having been determined in 2018.

74. The AER applies various "cross checks" to its decisions on the individual CAPM parameters.

75. The AER's methodology for determining the cost of debt includes an annual update, and the updated cost of debt figure will be "flowed through" automatically into authorised revenues each year. The methodology for calculating the updated cost of debt each year stays the same, but an additional year of data is used.

76. The AER's Rate of Return Instrument will be redetermined in 2022. If that redetermination results in a change in any of the parameters (MRP, equity beta, gearing and gamma), or in a change of methodology, the new parameters and methodology would be used in all revenue determinations subsequently. However, our understanding is that the changes to the Rate of Return Instrument would not have any impact on revenues authorised under already-existing revenue

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38 In addition, the Rate of Return Instrument also specifies the value of imputation tax credits (gamma), which is not directly a component of the rate of return but is used in calculating the tax building block, as we explain below.

39 The AER's cost of debt methodology is essentially a 10-year trailing average of the market cost of debt, as at a time close to when the revenue determination takes place.

determinations. Thus, for example, the Energex 2020-25 determination we discuss below would be unaffected by any changes to the Rate of Return Instrument which take place in 2022. Any changes to the rate of return methodology (or parameters) would not have an impact on the Energex authorised revenues until the next control period, beginning in 2025.

2. ACM

77. We characterise the ACM's regulatory objective as "efficiency", similar to the AER, although the ACM's mandate also includes security of supply, sustainability and providing investors with a reasonable return.

78. Although the utilities regulated by the ACM are government-owned, the ACM ignores this when determining the rate of return.

79. Like the AER, the ACM sets five-year revenue determinations. Unlike the AER, however, the ACM's rate of return methodology is determined in the same proceeding as the revenues are determined. There is no separate rate of return proceeding.

80. Unlike AER, the ACM targets a pre-tax WACC, so the tax component of the revenue requirement is effectively a gross-up.[40] This means that in order to compare the actual rate of return itself with an AER decision, we would need to look at the WACC before the tax gross-up is applied.

81. Like the AER, the ACM uses the CAPM to determine the cost of equity, and uses a bond index to estimate the cost of debt. However, unlike the AER there is no annual updating of the cost of debt, although there is an element of forecasting in the ACM's cost of debt methodology.

82. Unlike the AER, there is no updating of the rate of return during the revenue control period.

83. The AER and ACM do not implement the CAPM in the same way and there are important differences in how the parameters are estimated (which we discuss further below).

3. FERC

84. The FERC's overall objective (and the legal standard for its decision-making) is that utility rates must be "just and reasonable". In practice, FERC seeks to set a rate of return which is equivalent to what investors could obtain elsewhere from investments of similar risk.

85. FERC determines maximum prices, rather than maximum revenues. However, for both natural gas pipelines and electricity transmission utilities, most revenue comes from charges for capacity rather than throughput. Thus, we would not expect a significant difference in terms of revenue risk.

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40 See discussion above in section I.C.

86. Unlike Australian utilities, US natural gas transmission pipelines and electricity transmission utilities do not have revenues (or rate base) indexed to inflation. Thus, FERC considers nominal rates of return, whereas the AER targets a real return. Investors in US utilities have a different inflation exposure from that seen by investors in Australian utilities.

87. For the most part, FERC determines the rate of return in the same proceeding as revenues are determined. The exception is that FERC sometimes determines the return on equity for a group of utilities together, with revenues determined subsequently in separate proceedings. FERC typically does not re-examine its rate of return methodology in each proceeding, but tends to stick with the same methodology it has used previously.

88. Unlike the AER, FERC does not determine revenues or the rate of return for a pre-specified five-year period. FERC proceedings can be launched any time that customers, the utility, or FERC itself thinks that rates should change.[41] In practice, this means that some FERC-regulated utilities can go for many years between rate cases (ten years or more). However, FERC's rate of return methodology at a given date is the same independent of the length of time since the last rate case.[42] Of note, the FERC's rate of return decisions can be and are sometimes appealed to the courts, which in recent years have caused several changes to the rate of return methodology—most notably the reliance on multiple models with equal weight.

89. FERC determines a nominal return on equity, but does not always set an overall rate of return. Whereas the AER implements the CAPM to determine the cost of equity, the FERC also uses two other models: the DCF (discounted cash flow) model; and the Risk Premium model.[43] The DCF model forecasts future growth for a set of comparator utilities, using equity analyst reports and other data, and estimates a discount rate that makes current share prices consistent with the growth forecasts. The Risk Premium model estimates an equity premium by examining a large dataset of prior cost of equity determinations (including some reached by settlement). For natural gas pipelines, FERC uses an equally-weighted average of the results from the CAPM and DCF models. For electricity transmission, FERC uses an equally-

41 Notably, customers are often sophisticated parties (large gas shippers, utilities, or state agencies), who have sufficient funds to hire experts on rate of return and other issues. We also note that electric transmission companies may have so-called formula rates, where certain (pre-specified) costs are updated annually.

42 We note that the majority of FERC rate cases (electric transmission and gas pipelines) are resolved through a settlement with shippers in the case of gas pipelines or utilities or state agencies in the case of transmission. In such cases the authorized return often is not disclosed – the settlement is a so-called black box.

43 Details of these methods are provided in the FERC appendix.

weighted average of all three models.[44] In contrast, the AER did not place any weight on the DCF model in determining its cost of equity methodology.[45]

90. If it is determining the authorised revenues in the same proceeding, FERC will authorise a gearing level and a cost of debt. Gearing is usually based on the actual gearing (book value basis) and the cost of debt is the embedded debt cost (i.e., the actual interest cost).

91. A new FERC rate of return decision has no impact on any utility other than the one to which that decision applies.

4. STB

92. The STB regulates certain freight railroads in the US. Unlike the AER, the STB does not automatically determine rates or revenues. Rather, the STB determines a rate of return each year, and then in certain circumstances it can determine maximum permissible rates where railroad customers do not have competitive alternatives. The STB also uses its rate of return determination to test the financial viability of the railroads.

93. The overall regulatory framework of the STB is rather different from the AER—in particular, the STB does not determine authorised revenue for a whole rail network, just for some uses and some parts of the network. Nonetheless, we think the STB is a relevant comparator because its rate of return methodology is based on estimating the cost of capital for the regulated activity, as is the AER's.

94. Consistent with the fact that it generally is not responsible for determining revenues, the STB's objective is to set a reasonable maximum rate when it needs to do so (in circumstances where there is no competitive alternative for rail shippers).

95. The STB re-determines the rate of return annually. However, the STB does not consider modifications to its methodology in these annual proceedings.

96. Since there is no inflation adjustment of revenues or rate base, the STB targets a nominal vanilla WACC (whereas the AER effectively targets a real vanilla WACC).

97. The STB estimates the cost of equity using the CAPM and a DCF model. It allows a cost of debt based on the average embedded debt of the industry. The rate of return is common to all railroads regulated by the STB, so each utility is allowed the same cost of equity and debt regardless of the individual utility's actual embedded cost of debt.

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44 It would be challenging to implement the Risk Premium model for natural gas pipelines because there tend to be far fewer cost of equity determinations (which are used in the risk premium model) for gas pipelines than for electricity transmission utilities.

45 The DCF model is similar to the DGM model discussed by the AER. See AER, "Explanatory Statement, Rate of Return Instrument," December 2018, pp. 79-82, 253-266.

98. The STB uses the CAPM to estimate the cost of equity, like the AER. Unlike the AER the STB also estimates the cost of equity using a cash-based DCF model.[46] The STB uses an equally-weighted average of the CAPM and DCF results as its cost of equity determination with gearing determined as the market-based gearing of the industry.

99. The STB's determines the rate of return annually, although due to the nature of the framework overall, the new rate of return decision will not necessarily have an impact on rates or revenues (because the STB does not directly determine revenues as a matter of course).

5. ARERA

100. Like the AER, ARERA's objective includes promoting efficiency.

101. Also like AER, ARERA determines revenues and the rate of return in separate proceedings, and ARERA targets a real rate of return.

102. Unlike AER, ARERA provides a tax gross-up rather than a detailed estimate of the tax expense, but like AER ARERA targets a real rate of return.

103. Like the AER, ARERA estimates the cost of equity using a variant of the CAPM. ARERA's cost of debt methodology is different from the AER's: ARERA estimates a debt premium based on historical returns,[47] and adds this to a current risk-free rate estimate.[48]

104. We can identify two particularly interesting differences between AER and ARERA in relation to how often the rate of return parameters are updated, and how quickly the updated parameters influence revenues. AER updates MRP and equity beta every four years, and the risk free rate whenever there is a new revenue determination; ARERA updates MRP, equity beta and the risk-free rate every three years. Thus ARERA updates MRP and equity beta slightly more often than the AER, but does not update the risk free rate so frequently because it updates all three parameters together (ARERA uses the same risk free rate to calculate both the cost of equity and the cost of debt). In addition, when AER updates MRP and equity beta, this does not influence revenues until the next revenue determination. In contrast, when ARERA updates these parameters, the change flows through into revenue in the year following.

46 The STB's DCF model is similar in principle to the FERC DCF model, but the details differ in that the STB relies on cash rather than dividends (see descriptions in the appendix).

47 The methodology is not described in sufficient detail to know the averaging period.

48 The risk-free rate is based on a one-year average of bond yields, together with other parameters including an overall floor of 0.5% real.

6. NZCC

105. The NZCC's objective is protecting consumer interests and promoting competition. While efficiency is not explicitly mentioned, we would expect efficiency to be an outcome of promoting competition (and that encouraging efficiency would protect consumer interests).

106. Like the AER, the NZCC determines revenues and the rate of return in separate proceedings.

107. The NZCC targets a real vanilla WACC, like the AER, and like the AER determines revenues for a five-year control period.

108. The NZCC and the AER also both rely on the CAPM to estimate the cost of equity. Unlike the AER, the NZCC determines the cost of debt as the risk free rate plus a debt premium. Also unlike the AER, the cost of debt is not updated during the revenue control period.

109. Similar to the AER, the NZCC determines the rate of return methodology and some of the CAPM parameters (MRP, equity beta and gearing) in a separate proceeding, and also like the AER it calculates the risk free rate and the cost of debt at the time of the revenue determination, following a predefined methodology determined in the rate of return proceeding.

110. While the AER is required to redetermine its rate of return instrument every four years, the NZCC is required to update its rate of return methodology no later than every seven years.

111. Like the AER, when the NZCC updates its rate of return parameters the new parameters do not influence revenues until after the next revenue determination.

7. Ofgem

112. Ofgem's overall objective is protecting consumer interests and promoting competition. Efficiency is mentioned as a subsidiary goal.

113. Unlike the AER, Ofgem does not have a separate proceeding to determine the rate of return, but rather determines the rate of return in the same proceeding as revenues are determined. We note, however, that unlike the AER, the revenue determination cycles of all of the utilities of a particular type (e.g., all 14 electricity distribution networks) are aligned. Therefore, while Ofgem regulates a similar number of utilities as does the AER, it has fewer occasions to determine revenues (and the rate of return) because many of the determinations happen in parallel.

114. Like the AER, Ofgem targets a real vanilla WACC, and it determines revenues for a five-year control period.[49]

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[49] Ofgem lengthened the control period to eight years as part of its "RIIO" reforms, but it appears to be moving back to a five year period now.

115. Ofgem's cost of debt method is very similar to the AER's, and like the AER Ofgem updates the cost of debt annually, with the results flowing immediately into revenues.

116. Ofgem's cost of equity method is also similar to the AERs: both rely on the CAPM. However, unlike the AER, Ofgem made an explicit adjustment to the CAPM-derived estimate of the cost of equity to reflect the cross-checks it applied and the other evidence it reviewed. Furthermore, Ofgem is proposing to apply an annual update to the cost of equity (by updating the risk-free rate) and that this would flow through into revenues immediately. In contrast, AER only updates the cost of debt.

8. Ofwat

117. Ofwat regulates water and waste-water utilities, and these utilities usually have a retail function.

118. Ofwat's overall objective is protecting consumer interests and promoting competition.

119. Unlike the AER, Ofwat does not have a separate proceeding to determine the rate of return, but rather determines the rate of return in the same proceeding as revenues are determined. However, that unlike the AER, the revenue determination cycles of all of the utilities regulated by Ofwat are aligned. Therefore, while Ofwat determines the cost of capital as part of the revenue determination, it only does so once every five years.

120. Like the AER, Ofwat targets a real vanilla WACC, and it determines revenues for a five-year control period.

121. Ofwat's cost of debt methodology is very similar to the AER's. Unlike the AER, Ofwat does not update the cost of debt each year and flow the result through into revenues. However, Ofwat has indicated that it intends to apply an ex post true-up which would presumably have a similar result.

122. Ofwat's cost of equity methodology is also similar to the AER's: both rely on the CAPM.

9. Observations

a. Context and overall framework

123. We do not observe significant differences across the regulators in terms of the way the overall regulatory framework operates. For example, most of the regulators set revenue controls rather than price caps. FERC is an exception, in that it authorizes prices rather than revenue. However, for both natural gas pipelines and electricity transmission, most revenue is recovered in capacity-based charges, which reduces volume uncertainty. The goal of the AER is to promote efficient investment in, and operation and use of, electricity and natural gas services for the long term interests

of consumers.[50] Some other regulators have goals also expressed in efficiency terms (ACM and ARERA), while other regulators (e.g., Ofgem, Ofwat, NZCC) have goals primarily expressed in terms of protecting consumer interests by promoting competition. The FERC's goal is to establish rates that are just, reasonable, and not unduly discriminatory or preferential.[51] We consider that these differences in the overall framework do not give rise to differences in the approach for determining the rate of return.

124. In particular, while the objectives of the regulators are expressed differently, we have not been able to identify any connection between variation in overarching objectives and variation in how regulators approach the determination of the rate of return. For example, the generally-accepted legal standard in the US is the "fair return", which explicitly benchmarks authorised returns to the returns investors can obtain elsewhere from investments of similar risk.[52] This seems to us conceptually similar to the approach each regulator takes to determining the authorised rate of return. Similarly, we have not identified any connections between differences in the overall approach to determining revenues and differences in the rate of return methodology.

125. Most importantly, all of the regulators determine the authorised rate of return by estimating the cost of capital demanded by investors supplying capital to the regulated utility.

126. The regulators we consider all set a weighted average rate of return with the exception of the US FERC.[53] A weighted rate of return is multiplied by the value of the rate base to give a dollar return, whereas the FERC allows separately a cost of equity, a cost of debt, gearing and a tax recovery. The ultimate result is comparable to a vanilla WACC, but in some proceedings FERC determines the ROE only, with the other parameters determined in separate proceedings. As can be seen in Figure 1 below, the majority of the jurisdictions considered determine a rate of return and separately (outside the rate of return) determine a tax allowance. This is true for all considered regulators except ACM and ARERA, which include the tax allowance in the authorised rate of return. The ACM and ARERA apply a simple "gross up" to the rate of return (i.e., they set a "pre-tax rate of return"), but do not have a separate tax allowance. The advantage of a separate tax allowance is that it allows a more precise estimate of the tax to be paid, taking into account the specifics of the tax

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50 "National Energy Objectives" at https://www.aemc.gov.au/regulation/regulation

51 Federal Energy Regulatory Commission, *Strategic Plan 2018-2022*, September 2018.

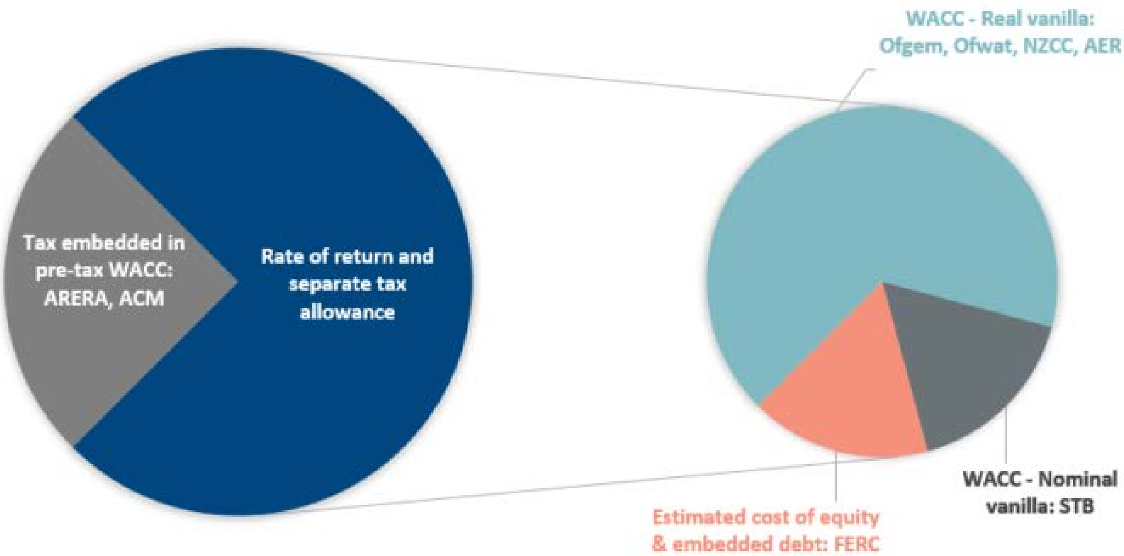
52 The US Supreme Court has said "the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks" (*FPC v. Hope Natural Gas Co.*, 320 US 591 (1944) and *Bluefield Water Works & Improvement Co. v. Public Service Comm'n*, 262 US 679 (1923), cited in FERC policy statement on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity, April 17 2008, p. 2).

53 The FERC determines an authorized return on equity and in most instances approves the embedded cost of debt and authorizes a level of gearing, albeit there are circumstances where gearing is not explicitly considered.

code. Also pre-tax returns are not comparable across jurisdictions because tax rates are typically different.

127. In Figure 1 we highlight the different "flavours" of rate of return that each regulator targets.

Figure 1
Rate of Return Method Used by Regulators



128. A second difference across regulators is whether they determine a nominal or real return. This issue needs to be described carefully because some regulators, including the AER, *report* a nominal rate of return, but in effect *target* a real return. AER and NZCC report a nominal WACC, but these regulators adjust the rate base and revenues for actual inflation. If there is an inflation shock, the dollar returns earned by investors will increase, so it is more accurate to describe these regulators as targeting a real return. In contrast, the FERC and the STB target a nominal return, and investor dollar returns in these jurisdictions would not increase if there is an inflation shock.

129. Ofgem, Ofwat, ACM and ARERA report and target real returns. AER and NZCC determine a nominal return but actually target a real return. FERC and STB target a nominal return.

130. Regulators vary with regard to the measurement of the components of the rate of return. There is no single element in which regulators agree on the exact approach albeit the degree of variations differ. However, there are elements where the level of "agreement" is higher than for other elements. This is illustrated in Figure 2 below, which shows that non-US regulators rely on a notional gearing and predominantly the CAPM to model the cost of capital, while US regulators use the target entity's gearing[54] and rely on several different models (with equal weighting).

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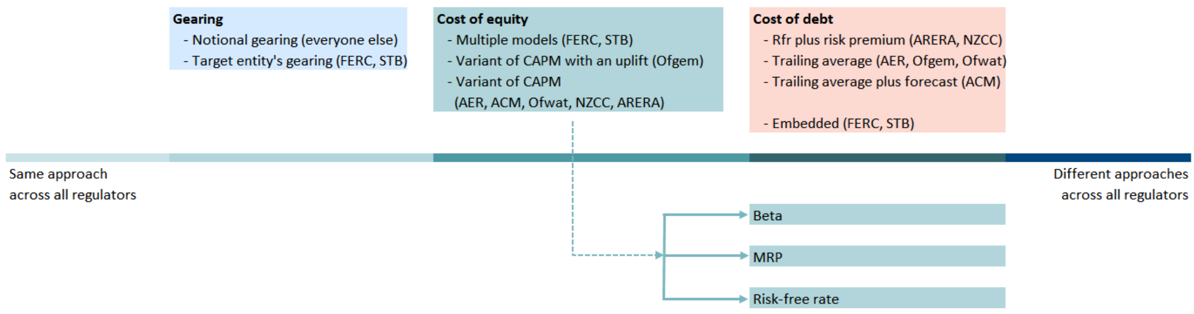
[54] *Ie*, the gearing of the utility for which the regulator is determining revenues.

We discuss and contrast these differences below. The biggest variation across regulators in terms of the detail of the methodology is in how the cost of debt is estimated.

Figure 2
Overall Variation



b. *Timing and updating*

131. A key difference across the regulators is the timing of the process they go through to determine authorised revenues and authorised rates of return. Like the AER, most regulators determine revenues on a set schedule with five years being the most common (AER, ACM, Ofgem, and Ofwat). ARERA has a slightly longer period of six years and the STB is much shorter with an annual determination (STB's determination follows the same prescribed methodology each year, however). In contrast, the FERC does not have a pre-set horizon for a regulatory review, but hears cases when the utility, customers or in rate cases, the FERC itself request that rates should change.

132. The AER and Ofgem both update the cost of debt each year, and flow this update through into authorised revenues. The update process is very prescriptive and completely defined in advance, so far as we know, does not require any judgment when the cost of debt is updated.[55] Ofwat does not update the cost of debt but has said that it will retrospectively true up revenues for changes in the cost of debt at the end of the revenue control period.[56] As a new development relative to its prior practice, Ofgem has proposed that for the next revenue determination it will adjust its rate of return annually for the impact of changes in the risk-free rate on the cost of equity: changes in the risk-free rate will be flowed through one-for-one to the cost of equity (as with the cost of debt updating, this process would be completely

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55 In the AER's case, the updating methodology is determined and set out in the Rate of Return Instrument. In Ofgem's case, the methodology is determined as part of the revenue determination process.

56 We think that this process is thus broadly equivalent to Ofgem's or the AER's.

prescribed at the start of the revenue determination).[57] Ofgem is the only regulator we know of that also updates the cost of equity.[58]

133. The AER, ARERA and the NZCC review the rate of return in a different proceeding from that in which the revenue requirement and revenues are determined.[59] The AER reviews its Rate of Return Instrument every four years. As a result, for example, the current methodology and the current values of MRP and equity beta are being used and will be used for all revenue determinations until the Rate of Return Instrument is re-determined in 2022. The NZCC has a similar approach, with the rate of return methodology and the MRP and equity beta parameters contained in the "Input Methodologies", which must be reviewed no later than every seven years. ARERA determines the rate of return every six years, but updates its estimate of the MRP, inflation and the risk-free rate every three years. Importantly, ARERA flows through the impacts of changing the rate of return parameters into revenues in the next tariff year, whereas for AER and NZCC this does not happen until the start of the next revenue control period.

134. Other regulators determine the rate of return in the same proceeding as the revenue requirement is determined.[60]

135. There are pros and cons to any periodicity—an annual review ensures the data is up-to-date, and therefore that the authorised rate of return can reflect current capital market conditions. However, if the process is not highly streamlined (the STB's updates are streamlined in part because methodology questions are typically not included) it risks placing a substantial regulatory burden on the parties. Too long a period between updates means that the rate of return can fail to reflect changes in capital market conditions. When regulatory rate-of-returns are reset infrequently, it becomes important to consider whether market or industry conditions have changed substantially in between the resets. Furthermore, when updating some parameters but not others it may be important to consider the potential for interaction and inconsistency between parameter estimates.

c. Models for determining the cost of equity

136. All of the regulators rely on a version of the CAPM to estimate the cost of equity, although there are important differences of detail which we explore below. However, the two US regulators (FERC and STB) also estimate the cost of equity using one or two other models, and the final cost of equity determination is the simple average of the CAPM estimate and the estimate from the other model(s).

57 Ofgem RIIO-2 – Finance, pp. 9 and 30.

58 The Ofgem methodology we describe in this report is at the proposal stage and has not yet been implemented.

59 The STB is a special case: it determines the rate of return annually, but there is no regular determination of authorised revenue.

60 With the exception of the FERC (in relation to groups of utilities in an ISO) and the STB (which does not set revenue requirements).

This is a striking difference from the approach of the other regulators. All the other regulators either rely exclusively on the CAPM or very heavily on the CAPM, with some weight given to cross checks and other evidence. No reviewed regulator other than the FERC and the STB appears to put weight on other models beyond the CAPM.

D. Components of the rate of return methodologies

137. In this section we consider the components of the rate of return methodologies in more detail.

a. The cost of equity

138. The AER, like regulators in Europe and New Zealand, generally relies on the CAPM to determine the return on equity. While there are variations across all the regulators in the detail of which version or implementation of the CAPM is used and some (including the AER) check against other measure of the return on equity, the regulators in North America take a clearly different approach. The North American regulators (FERC and the STB) use several methods, including the CAPM, and broadly give results from all the models the same weighting.[61] The FERC and STB assign equal weight to the CAPM and DCF for pipelines and railroads, and to the CAPM, DCF and risk premium methods for electric transmission.

139. In its most recent decision, the AER considered cross-checks on the results of its "foundation model" (the Sharpe-Lintner CAPM) as well as its components. These cross checks came from independent valuation and broker reports, and other regulatory decisions in Australia. Ultimately, after considering the cross-checks, the AER made no adjustments to the results obtained from the Sharpe-Lintner CAPM. Ofgem also considered cross checks, based on RAB multiples from transactions and listed pure-play utilities, investment management forecasts, the results of OFTO licensing,[62] and discount rates used by infrastructure funds. Based on these crosschecks Ofgem increased the cost of equity by 0.1%.[63] In contrast, the FERC and the STB take the equal weighted average across the results from the CAPM and other models.

140. RAB multiples and the results from OFTO licensing are interesting because these are more or less direct market measures (from RAB multiples, of the difference

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61 We note that regulators in Canadian provinces and the US states generally also consider multiple methods for the estimation of the cost of equity.

62 OFTO is offshore electricity transmission. The value of these assets has been determined after construction, and the right to own and operate them is auctioned. The bidders bid the annual revenue stream they required over 25 years. The auction winner pays the determined asset value, and receives the 25 year revenue stream. Thus, a discount rate can be calculated from the auction results which provides information on the cost of capital for owning and operating such assets.

63 Ofgem RIIO-2 – Finance, p. 66.

between the cost of capital and the regulator's estimate of the cost of capital; and from the OFTO licensing, of the cost of capital directly). The OFTO license results are effectively an auction where the value of offshore transmission assets is announced up front, and bidders compete to own and operate the assets and bid the smallest future revenues that they will accept. Although the OFTO results are directly market-based, they are not fully comparable. For example, the OFTO assets are already constructed, and the OFTO revenues are fixed for 25 years without re-opener. Also there is limited scope for "outperformance", although there is "performance risk" because of penalties for poor availability. Therefore both construction risk and regulatory risk are arguably different from those of onshore utilities. Ofgem concluded that the OFTO results supported a cost of equity towards the top end of the of the CAPM range.[64]

141. While the use of the OFTO licensing implied cost of equity is interesting, we note that a generic use of RAB multiples has been rejected by, for example, the Alberta Utilities Commission as there were no recent transactions of pure play entities.[65] We concur that there is a significant difference between observations from transactions of pure-play entities and the price-to-book ratios of publicly traded utilities. However, both types of price-to-book ratios depend on a variety of factors, so that there is no straightforward conclusion to be drawn from such information.

142. The use of multiple models provides additional information.[66] Relying on multiple models, or a crosscheck based on alternative models, allows the regulator to consider a broader set of information about market conditions and the industry. For example, the CAPM using a historical MRP relies on backward-looking information, while the Dividend Growth Model (DGM) uses forward-looking information. During periods of changes in financial markets, it becomes important to consider both historical (stable) and forward-looking (contemporaneous) information. In the following we focus on how some regulators broaden the information they rely on while still focusing on the CAPM, noting that other regulators (FERC and STB) go further to rely equally on the CAPM and other models.

143. Relying only on the CAPM is straightforward provided the inputs are well specified and readily available. It is important that the data sources are reliable and widely available, or the CAPM results may not be reliable. While data on the risk-free rate and a multitude of measures of the market risk premium are broadly available in

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64 RIOO 2 – Finance, para 3.138.

65 Alberta Utilities Commission, "Decision 22570-D01-2018: 2018 Generic Cost of Capital," August 2, 2018, para 478.

66 Stewart C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," *Financial Management*, Autumn 1978, p. 67 and Stewart C. Myers, "Estimating the Cost of Equity: Introduction and Overview," submitted to the AER on behalf of the Australian Pipeline Industry Association, February 2013, p. 13. The same sentiment is reflected in the MBA text of Jonathan Berk and Peter DeMarzo, *Corporate Finance: The Core*, 3rd edition, 2013, p. 466.

the jurisdictions considered, there may be relatively few comparable companies available in any one country.

144. The DGM model similarly is straightforward provided the inputs (dividends or cash flows, growth rates, and stock prices) are well specified and readily available. Also, as with the CAPM it is important that the data sources are reliable or the results may not be reliable. Commonly, data on the dividends (or cash flows in the case of the STB) and prices are readily available, so the dividend (or cash) yield is easy to calculate. However, growth rates may be less widely available for some companies or in some jurisdictions.

145. The AER prefers locally-based companies, which leaves a very small sample, while some European regulators (ACM, Ofgem, ARERA) often rely on companies from other European jurisdictions (or in some cases North American companies).The NZCC uses a very broad set of companies from different jurisdictions. While even in the US there are very few listed pure-play gas pipelines, for gas and electricity distribution there is generally a large sample of companies to choose from in North America. If utilities that operate in different jurisdictions have comparable business risks and regulatory frameworks (including all of the jurisdictions in this report that regulate energy utilities), the use of betas from a non-Australian market can provide information about the systematic risk of the industry in Australia. Measuring beta can be unreliable if the local market index is not diverse. However, we note that the Australian, the UK and US stock market indices are quite diverse with no one industry accounting for more than about 18% of the index.[67] Thus, in these cases, the beta estimates against the local index are likely to reflect readily available diversification options. Therefore, a beta estimate would reflect reasonably well the systematic risk of the utility peers against a broad market index. Nonetheless, we recognise that each local market may have specific features that could make it challenging to use equity beta estimates from one market in another – especially those with limited diversity or liquidity.[68] Thus, the inclusion of international peers need to consider the diversity and liquidity of the market index used in the estimation of beta. We note that the ACM checks for the liquidity of stocks of the relied upon comparators.

146. With a sufficient number of comparable companies available for beta estimation, well-specified inputs **and** relatively stable market conditions,[69] the CAPM results in predictable outcomes.

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67 In Australia materials is the largest group at about 18% of the market capitalization, while in the US technology is the largest share at about 18% and in the U.K. consumer staples is largest – also at about 18%.

68 Among the jurisdictions studied, the Italian index, FTSE MIB, is quite narrow with only 40 members and 35.5% and 20% of the market capitalization concentrated in financials and communications, respectively. Source: Bloomberg.

69 During the month of March 2020, most financial markets (including Australia) saw large volatility in stock prices, declining risk-free rates, and changes in forecasted MRPs. Hence, it would be challenging to provide predictable or stable results using the CAPM during such a period.

147. Similarly, the DGM depends on the availability of comparable companies for growth rate and dividend yield estimation. Of specific concern regarding the DGM is whether unusual movements in stock prices or growth rates influence the results. Thus, similar to the CAPM, it is necessary to have well-specified inputs and relatively stable market conditions to obtain reliable results.

148. The use of more than one method means that additional information about the market and the peers / industry is incorporated into the ultimate determination, and tends to reduce the impact of any one unusual input parameter. Importantly, many of the characteristics of the CAPM or any other model (including the DGM) depends on the details of how it is implemented. Often, adjusting the details of how the model is implemented can avoid unreliable outcomes: it is usually not advisable to specify in advance the details of how the models will be implemented before the actual inputs are available. Thus, for example, if a large number of the comparators in a given industry face negative growth rates at a given time, a standard implementation of the DGM might result in negative cost of equity estimates, which make no economic sense.

149. In the Australian context, a key issue is the availability of comparable companies for the proper estimation of beta. Because there is a limited number of publicly-traded utilities in Australia,[70] finding appropriate Australian comparators is a problem, albeit one shared with other potential models. The CAPM is very sensitive to the assumptions on the risk-free rate and especially so if a single date or a short averaging period is used for the calculation. Similarly, depending on the implementation, the determination of the MRP and the interaction of the risk-free rate and MRP can substantially affect the results of the model. Because the model is generally applicable to any sector, it does not specifically take the regulatory context into account—of the models used by other regulators, only the risk premium model of the FERC does. All in all, the CAPM is a well-founded and commonly used model that relies primarily on readily available information. However, it can be overly variable (or unstable)—i.e., produce results which are sensitive to exactly when the estimates are done—because changes in interest rates affect the risk-free rate and market volatility affects the beta estimates. Thus, it is not clear that the MRP or beta remains constant as the risk-free rate changes. Instead, Bloomberg's analyses of the forward-looking MRP show that the MRP increases as the risk-free rate declines, so that the resulting market return moves less than the risk-free rate.[71] As for the

70 The Staff Study on Beta p. 15 found four companies for the period ending May 2017.

71 For example, Bloomberg's estimate of the MRP for Australia and the Australian 10-year bond yields are inversely related since 2015, so that the MRP increases when the risk-free rate declines and vice versa. Bloomberg calculates Australian forward-looking MRP using a multi-stage DGM using the companies in the ASX index and weighting the companies by their market share. The multi-stage DGM converges the company-specific growth rates based on analysts' forecasts to the forecasted GDP growth over a period of 10 years. The MRP is measured over the 10-year Australian government bond yield.

beta estimates, we recommend a period long enough to create stability and statistically meaningful estimates. Yet, the period should reasonably reflect the current systematic risk of utilities as well as market conditions; textbooks generally recommend a window of 2–5 years. Finally, the magnitude of the MRP has a significant impact on the CAPM results, but the determination of the MRP remains controversial.

150. While the CAPM as well as other models (including the DGM) have both strengths and weaknesses as a model, it is important to realize that many aspects of the performance of the models depend on the details of how they are implemented. As the focus of many regulators is the CAPM, we discuss good practice in implementing the CAPM below.

151. First, the CAPM will provide regulated entities with a reasonable return only if it is implemented accurately, and the analyst must take any unique circumstances that may bias the estimates into account. Second, provided that the regulator specifies the relied upon model and data sources, the model is very transparent. Third, if the data sources are widely available and well-specified, the results can be replicated by interested parties. Fourth, the model may but is not guaranteed to produce similar results for similar conditions. The model's result will be more consistent if a portfolio approach or a set of comparator companies is used to estimate betas. Fifth, the model is very sensitive to the estimates of the risk-free rate, beta and MRP. Short-term risk-free rates tend to change more quickly than long-term rates, so use of the long-term risk-free rate generally results in a more stable estimate. Beta estimates can be quite sensitive to market developments and therefore are sensitive to economic factors, but not necessarily in a manner that makes sense (i.e., may give results that are inconsistent with prior expectations about beta). This is particularly an issue in stock markets where one or more industries that are sensitive to economic policy or distress dominate the market. Therefore, it is important to note that the index against which beta is estimated is reasonably diverse (as discussed above). From a practical perspective, the portfolio approach to estimating beta tends to provide more stable results than do the company specific estimation methods, but the estimates remain sensitive to market changes. Sixth, assuming that the regulator relies on standard data sources, the model is pragmatic in the sense that it is based on readily available information that is either free or relatively inexpensive to obtain. Seventh, the model is also pragmatic in that it is relatively easy to implement. Eighth, because the model was developed as a generic approach to determine the cost of capital for companies, it does not specifically take the regulatory context into account.

152. All in all, the CAPM is a well-founded and commonly used model that relies primarily on readily available information. However, it may be less stable than ideal for a model that is used to set rates for several years because changes in interest rates affect the risk-free rate and market volatility affects the beta estimates. Finally, the MRP is a fundamental parameter of the CAPM but is not directly observable, and estimating it remains controversial. By this we mean that there are different methods for estimating the MRP which give inconsistent results from the same

input data (e.g., the use of long-run geometric averages to determine the expected MRP). For these reasons, we believe it is important to recognize that the input parameters cannot be viewed in isolation – they interact with one another. In short, it is important the regulator uses judgment about the reliability of the models and the relied upon inputs at a given point in time.

153. As noted above, all regulators reviewed use the CAPM either exclusively or in combination with checks or other estimation methods.[72] First, we discuss how these regulators implement the CAPM and second, we discuss the relied upon inputs to the CAPM: (1) equity beta, (2) the risk-free rate, and (3) the market risk premium. We also discuss implementation issues related to (4) the use of gearing and (5) the imputation of tax credits when applicable.

CAPM version

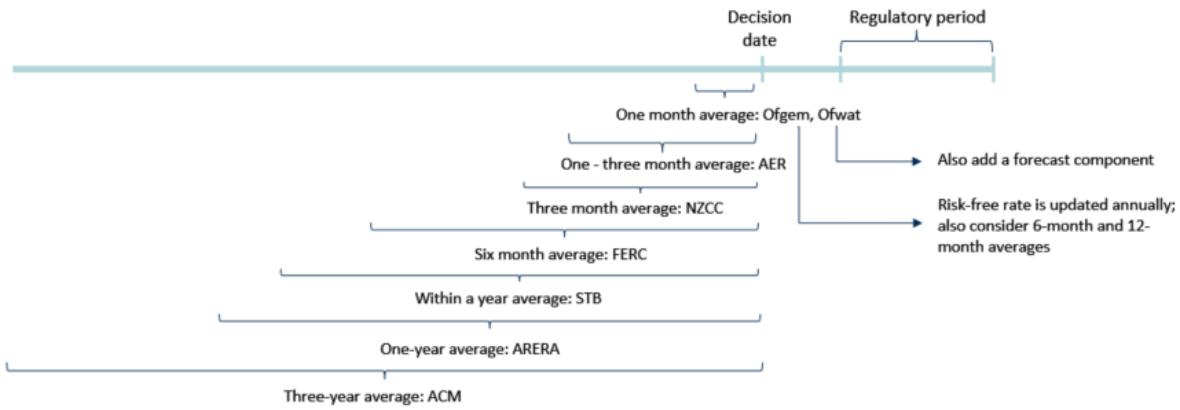
154. Regarding the CAPM and varieties hereof, the AER, ACM, FERC, STB, and Ofwat ultimately rely on the Sharpe-Lintner CAPM, while ARERA, NZCC, and Ofgem uses a modified version. In the case of ARERA the return on equity is calculated as the sum of a risk-free rate, a country risk premium, and an equity risk premium. The NZCC uses a simplified Brennan-Lally CAPM that assumes that dividends are fully imputed.

Risk-free rate

155. With respect to the risk-free rate, the key difference in the approaches taken by different regulators is the timing for estimating the risk-free rate. Only Ofwat uses a forecast risk-free rate, other regulators (including the AER) use recent or a longer run of historical data. The horizon over which the risk-free rate is calculated differs. Importantly, all regulators rely on a long-term government bond for the risk-free rate with the most commonly used maturity being 10 years (AER, ACM, ARERA). The horizon of Ofwat, STB and Ofgem, and FERC is longer at 15, 20, and 30 years, respectively, and NZCC uses a shorter period (5 years). Ofgem intends to update its risk free rate estimate annually (so that the cost of equity will be updated annually during the price control). We illustrate the timing variation in Figure 3.

[72] The FERC added the CAPM to the models used for electric transmission in 2018 and to the methods used for gas pipelines in May 2020. Prior to those decisions, the FERC relied exclusively on a version of the DGM. Sources: FERC Docket EL11-66001, "Order Directing Briefs" (New England Transmission Owners), October 16, 2018 and FERC Docket No. PL19-4-000, "Inquiry Regarding the Commission's Policy for Determining Return on Equity," May 21, 2020.

Figure 3
The Risk-Free Rate



156. Some of the regulators, including Ofgem, Ofwat, the NZCC and the AER have relatively short averaging periods of one to three months, and are thus close to an "on the day" approach. This is in contrast to the ACM, which uses an average of the Dutch and German 10-year bond over the last three years. Other regulators uses a more recent period to average over with the STB and ARERA using a one-year horizon, while the FERC uses a six-month horizon.

157. Ofgem and Ofwat base their risk-free rate on the government bond yield in real terms (i.e., using yields on inflation-linked debt directly) and therefore do not need to translate a nominal return into a real return. This is in contrast to ARERA, AER and NZCC which determine a nominal risk-free rate and convert it to a real rate based on forecast inflation.

158. As for the merits of the various approaches, it is important that the maturity of the risk-free rate and that used to determine the MRP match. We see no issue in this regard with the methodologies we have reviewed. Additionally, the long-term bonds are a reasonable choice because utility assets are long-lived. The NZCC relies on a shorter maturity of five years for the risk-free, which (as noted by the NZCC) reflects the regulatory period.[73] However, this does not match the life of the assets being regulated.[74] As for the horizon over which to calculate the risk-free rate, it is important it reflects current and expected regulatory-period conditions. A too long horizon risks not fully reflecting current conditions. It is also important the estimate is reliable and not a reflection of a one day phenomena, so it needs to be long enough to ensure stability (or the "day of" needs to be chosen carefully). During periods where interest rates can be expected to change going forward, it becomes important to consider whether a re-estimation of the cost of capital (e.g., risk-free rate, MRP

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[73] NZCC, "Input Methodologies (Electricity Distribution and Gas Pipeline Services)," December 2010, p. 138.

[74] The NZCC also includes an allowance for the issuance of debt in its cost of debt and checks the estimates against confidential data on the cost of debt.

and beta) is necessary and whether the use of a forecasted rate can provide a reliable forecast.

Beta

159. Regarding beta, all regulators calculate beta using a group of companies comparable to the target utility, with all but the STB estimating a beta for each comparator rather than a portfolio of comparators. The STB uses a market-weighted portfolio approach. Key differences relate to the selection of peers (local market only or international), the window used to estimate beta, the periodicity of the underlying return data and whether the regulator uses an adjustment. These factors are summarized in Figure 4 and Figure 5 below.

160. There are pros and cons to using both domestic-only and international comparators for beta estimation. Looking first to the benefits. First, there are more companies if looking internationally in any industry than domestically only. Thus, if there is a lack of peers domestically, it may be beneficial to look internationally. Second, in some instances, the operations of comparators crosses borders and thus their operations may reflect that of both the domestic and international market. This is the case of, for example, North American pipeline companies, which commonly operate in both the US and Canada. It is also the case for certain utilities used as peers in Europe, which have operations in several countries. Third, to the degree that financial markets are integrated, international data provides evidence regarding the return investors require. Among the disadvantages and challenges of using international comparators are the choice of index against which to estimate beta or in the case of the DGM, which GDP growth to rely upon. We tend to believe it is preferable to estimate beta against the index or a regional index of the utility's domicile as the timing of economic cycles could vary internationally.[75] However, it is vital to ensure that the index relied upon consist of a reasonably diverse set of industries as is the case in, for example, Australia, the US, and the UK. Consequently, we find that beta estimates for Australian, UK, and US utilities against the ASX, the S&P 500, and the FTSE, respectively are reasonably representative of the systematic risk relative to the market.[76] Similarly, it is important to check that nothing unusual has happened in the market index being considered that could bias the estimate—e.g., a downgrade of the country, major national disaster, etc.

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75 The ACM relies on the European index EUROSTOXX TMI (a European index) for European comparators and on the S&P 500 for US comparators. To the degree that there are exchange rate risk, it will be important to ensure it does not unduly affect the estimates. In Euro-based countries considered by the ACM that is not an issue. In other cases, it may be necessary to convert all return to the same currency to avoid the estimates reflect exchange rate risks.

76 See footnote 68 above.

Figure 4: Beta methodologies

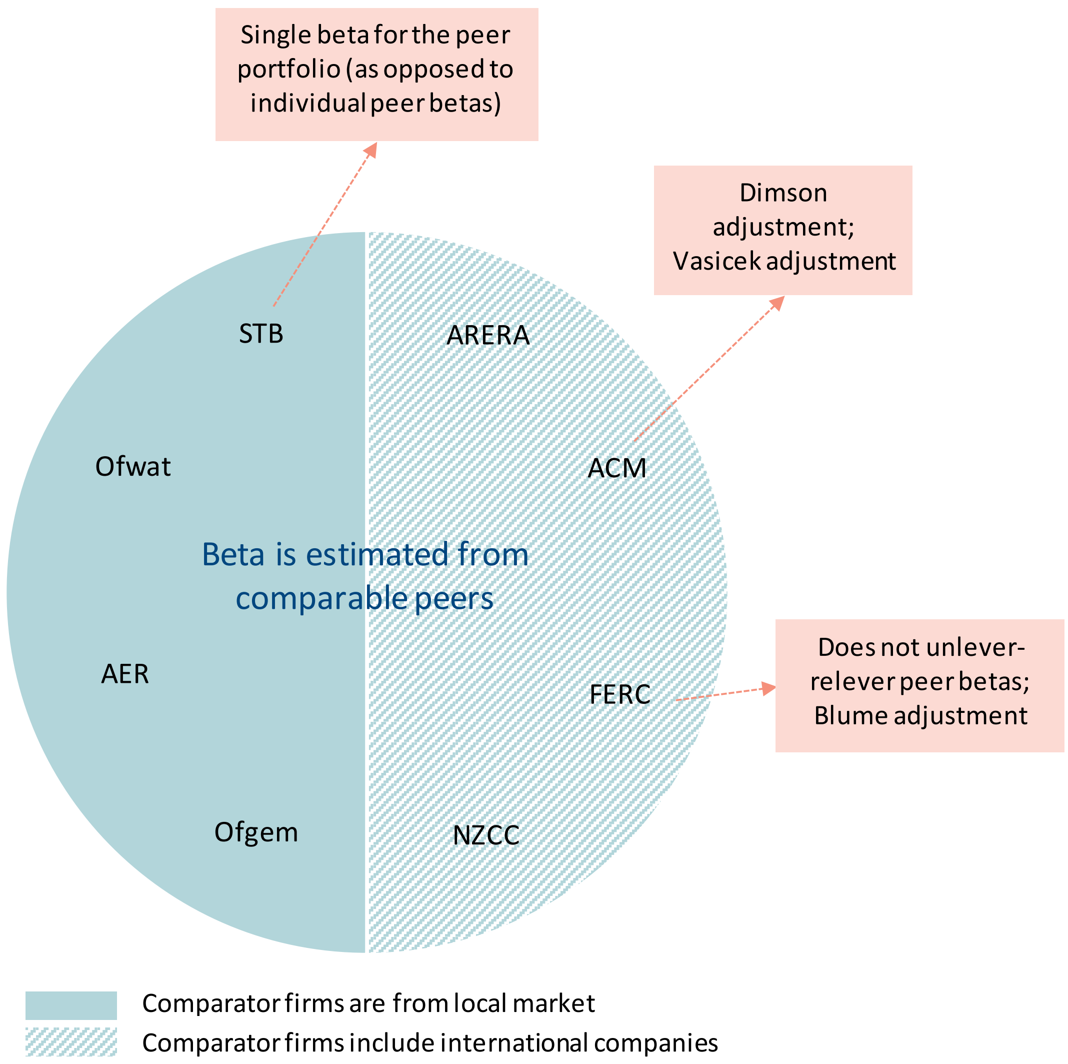
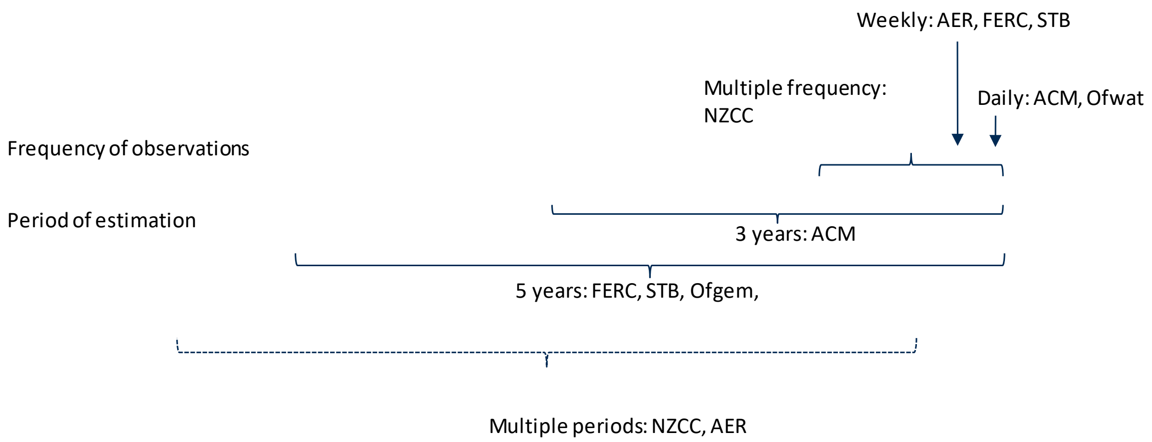


Figure 5: Beta estimation windows and return periods



161. The most common estimation window among the regulators is 3-5 years using daily or weekly data. This estimation window is consistent with the academic literature.[77] The AER and NZCC in contrast use multiple windows and periodicities of the data. The AER relied on some older data and some very long estimation windows. We consider the more common approach of using 3-5 years of data preferable to the longer horizons considered by the AER as long and/or historic data may reflect systematic risks that are no longer representative of current conditions. Not only do capital markets change over time—for example with the advancement of more technology-oriented companies and the displacement of older technologies—but utilities and their risk profile change, too. While we have not studied Australian utilities specifically, we have found in other markets that utility betas have varied over time by a non-trivial amount. We think that this is a real effect and not a measurement artefact. Thus, if there is limited data in a local market we think that, the addition of international comparators instead of lengthening the estimation window and risking the incorporation of out of date data merits consideration.

162. The AER and other regulators unlevers and relevers the estimated beta to target the gearing of the regulated entity. The FERC is unusual in that it largely ignores differences in capital structure.[78] While the ACM relies on the Dimson and Vasicek adjustment and the FERC relies on the Blume adjustment to beta; neither the AER nor the other regulators undertake such adjustments. These adjustments generally serve to move the estimated betas towards one (for example, recently in the US they tend to increase beta estimates for electricity transmission but reduce beta estimates for gas pipelines). In the case of both the Blume and the Vasicek adjustments, the reasons are based on statistical analyses that show the "raw" beta estimates are biased estimates of the expected beta, which is what the CAPM theoretically uses.[79] In the case of the FERC, they rely on the Blume adjustment because of the Blume study and because commercial providers of beta estimates report Blume adjusted betas. In the case of the ACM, they rely on the Vasicek adjustment, which takes into account the statistical reliability of the estimate and place higher weight on more reliable betas.

MRP

163. The last input to the CAPM, the MRP, tends to be among the more controversial inputs in that there are multiple methods that can be used to estimate the MRP and the results vary widely. The AER relies on a historical, arithmetic average as does ACM and the STB although the horizon over which the MRP is calculated differs.

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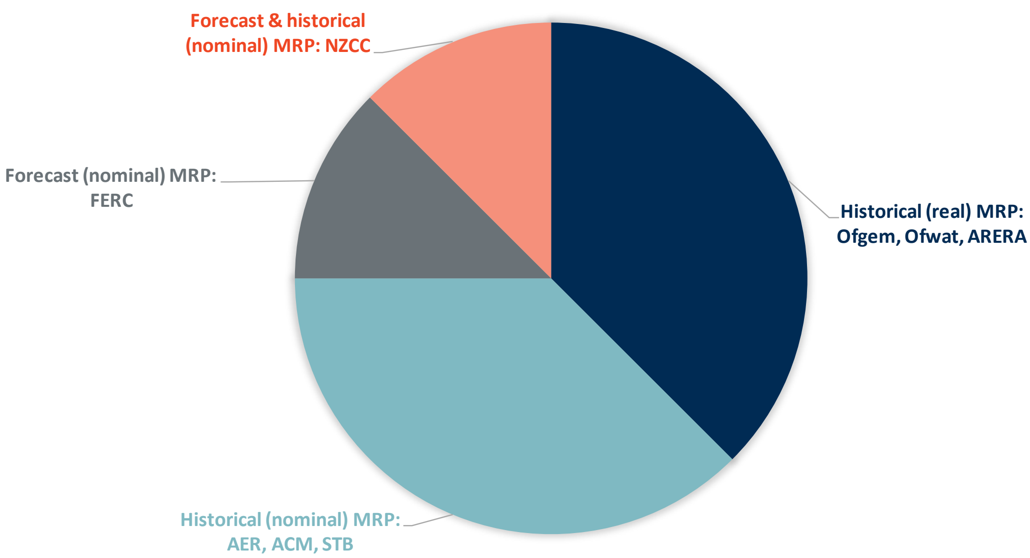
77 See, for example, Jonathan Berk & Peter DeMarzo, "Corporate Finance," 3rd Edition, 2014, p. 407 suggest that betas commonly are estimated using 2-5 years of data.

78 In cases, where the actual capital structure is considered unusual, the FERC may rely on a hypothetical capital structure.

79 M.E. Blume, "On the Assessment of Risk," *Journal of Finance* 26, 1971, pp. 1-10 and O.A. Vasicek, "A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas," *Journal of Finance* 28, 1973, pp. 1233-1239.

The AER relies primarily on data for 1988-2017 (30 years),[80] whereas the ACM[81] and the STB use a longer period (as long a period as there are reliable data), ARERA, Ofgem and Ofwat rely on a total market return (Wright) methodology with Ofgem and Ofwat considering several alternative methods to determine the total market return: ex-post, ex-ante, and a forward-looking approach, so that a range of potential MRPs are created. The FERC relies exclusively on a forward-looking MRP that is calculated using a DGM model and the NZCC uses a MRP which is reflective of both historical and forecasted estimates of the return on equity.[82] We illustrate this variation in Figure 6.

Figure 6
MRP



164. As noted above, it is important that the maturity of the MRP matches that of the risk-free rate. Additionally, when looking to a historical MRP, we note that the AER recognizes "that the geometric average is downwardly biased" as confirmed in the finance literature.[83] We also note that finance textbooks such as Ross, Westerfield and Jaffe recommend using as long a period as possible provided reliable data are available.[84] That is the approach explicitly taken by the ACM and FERC

[80] The AER looked at other measures including differing estimation windows, but ultimately chose an MRP reflecting the historical 30-year average.

[81] The ACM checks the historical MRP against a forward-looking MRP.

[82] The NZCC's estimate is also not comparable to those of the other regulators because of the way in which it treats imputation tax credits.

[83] AER, "Independent Panel: Review of the Australian Energy Regulator's Rate of Return Draft Guidelines," p. 33.

[84] Stephen A. Ross, Randolph W. Westerfield and Jeffrey F. Jaffe, "Corporate Finance," 10th Edition, 2013, p. 323.

and has the advantage of making the MRP very stable and predictable. Because Australia is a fairly open economy, it may have merit to consider international data – especially countries in which Australian utilities raise capital.[85] Because there is a substantial flow of capital between Australia and other countries, investors compare the return available in Australia and otherwise, so that we find the incorporation or at least a check against such data has value.

165. Looking to the total market return approach (e.g., the Wright model), we note that when the AER considered the Wright method in 2013, the AER observed the stability of the Wright method given that network assets are long-lived.[86] However, in the 2018 explanatory statement, the AER found that the Wright method's correlation with return on equity was not consistent.[87] Fundamentally, we view the consideration of multiple methods favourably as they provide different types of information. Using a single model implies placing zero weight on the information in other models, which we think is unlikely to be the best approach.

b. Cost of Debt

166. The area in which the regulators differ the most is with regard to determining the cost of debt. ARERA and the NZCC rely on the risk-free rate plus a premium, the AER and Ofgem use a trailing average of observed cost of debt, and Ofwat and the ACM amend the trailing average with a forecasted rate, while the FERC and the STB use the embedded cost of debt. While the AER's trailing average cost of debt approach is very similar to Ofgem's, the AER is also part way through transitioning to this method from a prior method. As a result, although the AER's current methodology will eventually be equivalent to a ten year trailing average, with equal weight on the cost of debt in each of the last ten years, the AER's current cost of debt only takes an average back to 2015, with 50% weight on the 2015 cost of debt (this weight will reduce over time as additional years are added to the trailing average). We understand that the cost of debt in 2015 was much higher than in more recent years and currently.

167. Additionally, some regulators allow for the recovery of issuance cost in the cost of debt (ACM, NZCC, Ofwat), while others (e.g., AER) allow such recovery in a

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85 We note that foreign investment into Australia as of 2019 was A$3.8 trillion (25.8% from the US and 17.8% from the UK). This compares to a market capitalization of about $A1.9 trillion for the ASX and a GDP of about $A1.9 trillion (foreign investments approximately 200% of both the ASX and GDP). On average, over the last three years, 2.2% of foreign investment into Australia went into electricity, gas and water utilities. Foreign investment into the US was about US$4.3 trillion and the market capitalization of the S&P 500 was US$28.1 trillion (so foreign investment was approximately 15 percent of the S&P 500). Australian investment abroad was $A2.9 trillion with 28.4% going to the US and 17.2% to the UK. (https://www.dfat.gov.au/trade/resources/trade-statistics/Pages/trade-statistics; https://www.bea.gov/international/).

86 Australian Energy Regulator, "Better Regulation: Explanatory Statement – Rate of Return Guideline (Appendices)," December 2013, p. 35.

87 Australian Energy Regulator, "Rate of Return Instrument – Explanatory Statement," 2018, p. 234.

separate line item of the revenue requirement and some decisions are quiet on the issue. We note that in its recent Energex decision, the AER's implied debt premium is higher than the implied equity premium by a small amount. This is in part due to the AER being in a transition from the prior methodology, with a significant weight on 2015 debt that will reduce over time. However, all other regulators being considered see a non-trivial difference between the equity premium and the debt premium (see Table 5 below). This is driven by the use of a negative real risk-free rate and more broadly, the methodology and parameters relied upon when estimating the return on equity. We note that the sum of the real risk-free rate and the debt premium is in line with that of other regulators.

168. Both Ofgem and the AER update the cost of debt annually during the price control period, using a trailing average of a corporate bond index. Ofwat incorporates a forecast but has said that it will true up for actual changes at the end of the price control period. We summarise these different approaches in Table 3.

Table 3
Cost of Debt

	Method	Period for estimation
AER	Trailing Average	Trailing: 10 years
ACM	Trailing Average + Forecast	10 years
FERC	Embedded	As of date
STB	Embedded	As of date
ARERA	Rfr + Country Risk +Debt Premium	
NZCC	Rfr + Risk Premium	Debt premium – 5 years
Ofgem	Trailing Average; updated annually	Trailing: 10 years
Ofwat	Trailing Average + forecast	Trailing: 15 years

169. We note that when a regulator uses a trailing average over a long period, the cost of debt is likely to be close to the industry's embedded cost of debt to the extent that the averaging method corresponds to the typical way in which the industry refinances its debt. Additionally, both the trailing average and the embedded cost of debt approach serve to stabilize the cost of debt and hence make the figure predictable. In contrast, the on-the-day approach and the Rfr plus risk premium can vary more over time as financial conditions and the risk-free rate change. The trailing average and the embedded cost of debt are likely to be closer to what a utility with a typical refinancing approach can achieve, but the on-the-day and the Rfr plus risk premium approaches capture financial market reality more quickly. Put differently, there is a trade-off between ensuring predictability / stability and reflecting current conditions.

170. The NZCC uses the three-month arithmetic average of a shorter maturity bond of five years. The NZCC determines the risk premium as the arithmetic average over

the most recent five year period.[88] While the five-year maturity matches the regulatory period in New Zealand, it does not reflect the fact that most of the assets subject to regulation are much longer lived than five years.[89]

E. Comparing authorised rates of return

171. For each regulator we reviewed, we documented an example of a recent rate of return determination, including the underlying components and model parameters where possible. In this section of our report we compare these determinations (quantitatively) across the different jurisdictions.

172. In order to make this comparison as meaningful as possible, we have in certain cases modified the figures actually reported by the regulator. We explained above that different regulators may use a different "flavour" of WACC in their revenue requirement calculations. The existence of different flavours complicates the comparison across jurisdictions. We also make a small number of other adjustments, documented below.

173. While the AER reports a nominal vanilla WACC in its decisions, the mechanics of the revenue requirement calculation are such that the AER aims to provide a real vanilla return.[90] We therefore consider that the most meaningful point of comparison between the AER and other regulators is a real vanilla WACC, which we can calculate from the AER's nominal vanilla WACC. Although the AER describes its rate of return as a nominal vanilla WACC, we consider that it is functionally a real vanilla WACC.

174. Real and nominal rates of return can be converted if an inflation estimate is available. At the time of a regulatory determination, if expected future inflation is I and the regulator determines a nominal rate of return of N, the expected real return is (N – I).[91] However, a nominal rate of return converted to real is not equivalent to the return set by a regulator that targets a real rate of return because the exposure

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88 NZCC, "Guidelines for WACC Determinations Under the Cost of Capital Input Methodologies," April 30, 2018, pp. 14-15.

89 The NZCC states that the term of the risk-free rate should be consistent with the term of the regulatory period. NZCC, "Input Methodologies (Electricity Distribution and Gas Pipeline Services)," December 2010, p. 138.

90 When calculating authorised revenues, AER determines revenue requirements as the sum of: opex, depreciation, tax and rate base x (nominal vanilla WACC). However, the depreciation building block is straight line depreciation minus expected inflation x rate base. This revenue requirement formula can therefore be rearranged as revenue requirement = opex + straight line depreciation + tax + rate base x (nominal vanilla WACC minus inflation). Nominal vanilla WACC minus inflation is a real vanilla WACC.

91 Or, depending on the mechanics of the revenue requirement calculation, (1 + N) / (1 + I) – 1.

to inflation risk is different. An investor in a US natural gas pipeline would see the value of its investment erode if there was an unanticipated period of high inflation (if the inflation were anticipated, presumably there would be a correspondingly high nominal rate of return determined).[92] An investor in a UK gas pipeline would not see the same erosion because the rate base is inflation indexed (as are revenues).

175. In theory a pre-tax or ATWACC can be converted into an equivalent vanilla WACC. This is straightforward, because all three of these WACC flavours use the same inputs.[93] However, a regulator (such as the AER) that uses a vanilla WACC will forecast the tax expense, which is typically a complicated calculation requiring data that would not be available in a jurisdiction that does not employ a vanilla WACC.[94] To put this another way, if a regulator working with an ATWACC and a tax gross up were to switch to forecasting the tax expense and using a vanilla WACC, it is likely that the dollar amount of the tax gross up and the forecast tax expense would be quite different (just as the "effective" tax rate is often different from the marginal tax rate), although this difference depends on the detail of the tax code in each jurisdiction. In Australia, for example, the vanilla WACC approach is likely to result in investors receiving a smaller return than they would do with a pre-tax or ATWACC approach, because under most circumstances the estimated tax will be smaller than the statutory tax gross up.[95] Where a regulator uses a pre-tax WACC in its revenue requirement calculations, we use the underlying components (the cost of equity and the cost of debt as well as gearing) to report a vanilla WACC equivalent.

176. In the discussion below, we compare the AER's June 2020 determination for Energex with recent decisions from seven other regulators. This comparison is summarized in Table 4, which shows the rate of return determinations for each regulator. In the bottom panel of Table 4, figures in bold are the overall rate of return figures reported by the regulators in the various decisions. Figures in regular type are the components of the rate of return as reported in the regulators' decisions. Figures in italics are calculated by us to facilitate comparisons across the

[92] The US investor is doubly exposed because not only would the value of the rate base erode, so would the revenues. We note, however, that a FERC-regulated entity can bring a rate case at any time.

[93] The inputs are the cost of equity and the cost of debt. The post-tax WACC and the pre-tax WACC also require the tax rate as an input. Note, however, the additional adjustment applied by ARERA (see footnote 250 below).

[94] The regulator will ask the utility to produce the necessary information to allow the tax expense to be forecast, but if the regulator is not forecasting tax that information would not generally be reported.

[95] Most companies will have an effective tax rate that is smaller than the marginal tax rate, for example because of accelerated (or "bonus") depreciation provisions in many tax codes. The exception would be a utility with older assets and a significant amount of accumulated deferred income tax. Since a tax gross up assumes that tax is paid at the marginal rate, and a tax allowance is based on a forecast of current taxes to be paid (i.e., the effective tax rate), the former is usually larger than the latter.

jurisdictions, as we explain below. We discuss each of the individual decisions in the appendix.

Table 4
WACC comparison

		AER	ACM	FERC	STB	ARERA	NZCC	Ofgem	Ofwat
Decision year		2020	2016	2020	2018	2019	2019	2019	2019
Nominal									
Cost of debt	[1]	4.76%	2.19%		4.16%		2.92%		
Cost of debt, excluding issuance cost	[2]	*4.76%*	*2.04%*		*4.16%*		*2.72%*		
Cost of equity	[3]	4.69%	5.02%	10.05% *	13.86% *		*5.87%*		
Equity beta	[4]	0.60	0.74	0.84	1.11		*0.65*		
MRP	[5]	6.10%	5.05%	8.60%	6.91%		*7.29%*		
Rf	[6]	1.03%	1.28%	2.70%	3.02%		*1.12%*		
Real									
Cost of debt	[7]	*2.49%*				2.39%		1.93%	2.14%
Cost of debt, excluding issuance cost	[8]	*2.49%*				*2.39%*		*1.93%*	*2.04%*
Cost of equity	[9]	*2.42%*				5.77%		4.80%	4.19%
Equity beta	[10]	*0.60*				0.706		*0.76*	0.71
MRP	[11]	*6.10%*				5.50%		*7.32%*	7.89%
Rf	[12]	*-1.24%*				1.89%		-0.75%	-1.39%
Other factor	[13]					0.49%			
Gearing, tax and inflation									
Gearing	[14]	60%	50%		16.92%	44%	42%	60%	60%
Tax rate	[15]	30%	25%			31%			
Composite tax rate	[16]					24%			
Expected inflation	[17]	2.27%	1.42%			1.70%	1.94%		
Rate of return									
Nominal vanilla WACC - as reported	[18]	**4.73%**			**12.22%**		**4.57%**		
Nominal vanilla WACC	[19]		*3.53%*				*4.55%*		
Real vanilla WACC - as reported	[20]							**2.88%**	**2.96%**
Real vanilla WACC	[21]	*2.46%*	*2.08%*			*4.27%*	*2.56%*	*3.08%*	*2.90%*
Real pre-tax WACC - as reported	[22]		**3.00%**			**6.31%**			
Nominal after-tax WACC - as reported	[23]		**3.33%**						
Nominal pre-tax WACC - as reported	[24]		**4.44%**						

Notes
Non-italized numbers come from the Appendix Tables corresponding to the individual regulators.
ACM: The latest method decision was issued in 2016 for for the regulatory period 2017 - 2021, in which the ACM determines a WACC for 2016 and 2021, then interpolates the WACC for each year of the regulatory period. The ACM also determines WACC for new and existing capital separately. This table shows the WACC determined for 2021 for new capital.
ARERA: Numbers shown are for gas distribution. Other factor is a tax adjustment factor. Risk-free rate is the 0.5% risk-free rate plus the 1.39% country risk premium.
*FERC: Uses three equally weighted methods to determine ROE. CAPM results are adjusted for size. Beta reflects median beta.
*STB: Uses two equally weighted methods to determine ROE.
NZCC: Equity beta and MRP are adjusted by the same factor to achieve a return on equity that would give the end 67th percentile nominall vanilla WACC
Ofgem: Equity beta and MRP are adjusted by the same factor to achieve a return on equity that would reflect the expected outperformance and uplift to cost of equity
AER real cost of debt, cost of equity and rf = nominal numbers minus inflation
[2][8]: cost of debt minus issuance cost.
[19]: [2] x [14] + (1 - [14]) x [3]
[21]: [8] x [14] + (1 - [14]) x [9], except NZCC and ACM, where the real vanilla WACC is estimated from nominal vanilla WACC and inflation.

177. Based on the figures in Table 4, we have also calculated debt premium and equity premium figures. These amounts are simply the cost of debt less the risk-free rate, and the cost of equity less the risk-free rate, respectively, shown in Table 5.

Table 5
Summary of equity and debt premium

		AER	ACM	FERC	STB	ARERA	NZCC	Ofgem	Ofwat
Decision year		2020	2016	2020	2018	2019	2019	2019	2019
Nominal									
Cost of debt, excluding issuance cost	[1]	*4.76%*	*2.04%*		*4.16%*		*2.72%*		
Cost of equity	[2]	4.69%	5.02%	10.05%	13.86%		*5.87%*		
Rf	[3]	1.03%	1.28%	2.70%	3.02%		1.12%		
Equity premium	[4]	*3.66%*	*3.74%*	*7.35%*	*10.84%*		*4.75%*		
Debt premium	[5]	*3.73%*	*0.76%*		*1.14%*				
Real									
Cost of debt, excluding issuance cost	[6]	*2.49%*				*2.39%*		*1.93%*	*2.04%*
Cost of equity	[7]	*2.42%*				5.77%		4.80%	4.19%
Rf	[8]	*-1.24%*				1.89%		-0.75%	-1.39%
Equity premium	[9]	*3.66%*				*3.88%*		*5.55%*	*5.58%*
Debt premium	[10]	*3.73%*				*0.50%*		*2.68%*	*3.43%*

Notes
Non-italized numbers come from the Appendix Tables corresponding to the individual regulators.
ACM: The latest method decision was issued in 2016 for for the regulatory period 2017 - 2021, in which the ACM determines a WACC for 2016 and 2021, then interpolates the WACC for each year of the regulatory period. The ACM also determines WACC for new and existing capital separately. This table shows the WACC determined for 2021 for new capital.
ARERA: Numbers shown are for gas distribution. Risk-free rate is the 0.5% risk-free rate plus the 1.39% country risk premium.
[1]-[3];[6]-[8]: see Table 4.
[4]: [2] - [3]
[5]: [1] - [3]
[9]: [7] - [8]
[10]: [6] - [8]

178. In the sections below we first explain how we obtained the numbers reported in the tables (in italics) that are calculated by us rather than directly reported by the regulators in their determinations. We then compare each decision with the AER's decision for Energex, highlighting which figures are comparable and which are not.

1. AER

179. In the bottom panel of Table 4, beneath the "rate of return" sub-heading, we report the figure that the regulator ultimately determined as the rate of return. Bold figures in this panel are taken directly from the regulators' decisions. For example, the AER's decision for Energex was to use a nominal vanilla WACC of 4.73%. As discussed above, we consider that although the AER reports a nominal vanilla WACC, it targets a real rate of return, and the value of an investment in Energex is not affected by inflation shocks in the same way that an investment in a US gas pipeline would be, due to the indexing of the rate base and revenues. We therefore calculate a real vanilla WACC.[96] The real vanilla WACC of 2.46% is also shown in the rate of return panel of Table 4, but is shown in italics because we calculated this number and it does not appear anywhere in the AER decisions or models.

180. The top panel of Table 4 ("nominal") shows the components of the AER's rate of return determination for Energex (i.e., the CAPM parameters). All of these figures appear in the AER's decision document. Similarly, the figures in the "tax and inflation" panel also appear in the AER's decision document.

96 We calculate the real vanilla WACC as nominal vanilla WACC minus expected inflation (this arithmetic mirrors the way in which the revenue requirement is calculated—see, for example, the Post Tax Revenue Model published as part of the Energex determination).

181. In the "real" panel of Table 4 we show the equivalent components (CAPM parameters) that would result in the real vanilla WACC of 2.46%. Equity beta, MRP and gearing are the same as in the "nominal" panel, and the risk-free rate and the cost of debt are adjusted for expected inflation.

2. ACM

a. Calculating the figures in Table 4

182. The ACM calculates different WACCs for each year and for "new" and "existing" capital, and the WACCs for each year are calculated by interpolating between a "2016 WACC" and a "2021 WACC", as we explain in the appendix below. In Table 4 we show the WACC for new capital for 2021—we show 2021 rather than 2016 because this is closer in time to the AER's Energex decision, and we show new rather than existing capital because the averaging period for the cost of debt has a better overlap with the AER's approach. The ACM has an explicit allowance for debt-raising costs and it includes that in the cost of debt. In contrast, the AER includes debt-raising costs in the opex building block. To make the figures comparable, we adjust the ACM's cost of debt to remove the ACM's allowance for debt-raising costs.

183. The ACM targets a real pre-tax WACC. However, the ACM calculates its real pre-tax WACC by grossing up a nominal post-tax WACC for taxes, and then adjusting for inflation. Since the ACM reports the components of the nominal post-tax WACC (i.e., the cost of debt and the cost of equity), we can simply combine these figures to produce a nominal vanilla WACC. We do this using the adjusted cost of debt (i.e., without debt raising costs) to find a nominal vanilla WACC of 3.53%.

184. We can then calculate a corresponding real vanilla WACC of 2.08% by adjusting for inflation.[97]

b. Comparing with the AER determination for Energex

185. The best way of comparing the overall returns authorised by the AER and by the ACM is to look at the real vanilla WACC (2.46% for the AER vs 2.08% for the ACM). Although these decisions were taken quite a long way apart in time (2020 vs 2016), and using market information from different countries, overall results are quite similar. However, there are some more significant differences in the underlying components of the rate of return.

186. The AER has a much higher cost of debt than the ACM (4.76% vs 2.04%). This may be in part because the ACM uses an index of A rated utility bonds, whereas the AER uses both A and BBB bonds, but it does not explain the full difference. Part of the difference may be due to the AER's transition to the trailing average approach not yet being complete. Further, the MRP in Australia is non-trivially higher than that

97 We adjust for inflation using real vanilla WACC = (1 + nominal vanilla WACC) / (1 + expected inflation) – 1.

of the Netherlands – indicating that investors require a larger premium for holding securities that are not risk-free in Australia than in the Netherlands.

187. The AER's equity premium (the difference between the cost of equity and the risk free rate) is similar to the ACM's (3.66% vs 3.74%), although the ACM's equity beta is higher and the ACM's MRP is lower.

3. FERC

a. Calculating the figures in Table 4

188. The FERC does not report a WACC figure per se but rather estimates the cost of equity and then adds an allowance for the cost of embedded debt. In Table 4 we report FERC's cost of equity figure, as well as the parameters from FERC's CAPM analysis (FERC's final determination for the cost of equity relies on three models: CAPM, DGM, and a risk premium models).[98]

b. Comparing with the AER determination for Energex

189. Since the FERC provides a return on embedded debt (generally allowing both actual gearing and actual interest rates), the only rate of return parameter we can sensibly compare with the AER's Energex decision is the cost of equity. The AER's cost of equity is much lower than FERC's (4.69% vs 10%).

190. The AER's equity beta, MRP and risk free rate are all lower than the FERC's. The AER's equity premium is less than half of the FERC's (3.66% vs 7.35%). The AER's equity beta and MRP are both lower than FERC's, by similar amounts (about 30%). Although the FERC's CAPM-based equity premium is much higher than the AER's, the FERC's result is confirmed by its DGM and risk premium cross check. Some of the difference is explained by the FERC's use of 30-year government bonds as compared to the AER's use of 10-year government bonds for the risk-free rate. These differences are consistent with utilities in the US generally raising debt with a 20-30 year maturity, while Australian debt often has less than 20-year maturity. As for the beta estimate, an important difference is that AER relies on several estimation periods: longest available, post tech boom and financial crisis of 2008, and most recent five years. The AER chooses to "place the most reliance on the data from the longest available period."[99] The AER five-year estimate indicated a beta range of 0.49 to 88.[100] Thus, the use of longer horizons differs from the FERC's exclusive use of the most recent five years. Consequently, the AER's beta estimates are more stable than those of the FERC, while the FERC's betas are more reflective

98 The most recent FERC decision does not indicate a cost of debt as that was not part of the review undertaken by the FERC in Order 569-A, which is its most recent guideline to determining the cost of equity. The order pertains to group of transmission owners; each of whom will be allowed recovery of their embedded cost of debt.

99 AER, "Rate of Return Instrument: Explanatory Statement," December 2018, p. 99.

100 *Ibid.*, p. 189

of the recently observed systematic risk. The difference is amplified by the AER data being as of September 2018, while the FERC data are as of early 2020. Lastly, FERC's betas are Blume adjusted, while the AER betas are not.[101] The key driver of the FERC's higher ROE is the reliance on a forecasted MRP and the higher actual risk-free rate.

4. STB

a. Calculating the figures in Table 4

191. The STB reports a nominal vanilla WACC, shown in bold in Table 4. We also show the underlying cost of equity and cost of debt, and we show separately the parameters from STB's CAPM analysis, and the cost of equity it ultimately relied on (based on both CAPM and DGM models).

b. Comparing with the AER determination for Energex

192. We should emphasise that the STB determines a rate of return for freight railroads. Equity beta and gearing tend to be significantly higher for railroads than for energy assets (for example, comparing the STB parameters with the FERC parameters).The AER determined a nominal vanilla WACC of 4.73% whereas the STB has an equivalent figure of 12.22%. We do not show a real vanilla WACC for the STB in Table 4 because the STB does not determine an inflation forecast. Nonetheless, it is likely that an inflation forecast would be around 2%, so the real vanilla WACC for the STB is likely to be around 10%.

193. The dramatic difference in vanilla WACCs is due solely to differences in the cost of equity, and gearing (the AER and STB cost of debt estimates are similar—4.76% vs 4.16%).

194. In part the STB's high cost of equity result is due to relying on an average of CAPM and DGM cost of equity results, and the latter is likely to be anomalous for the year being considered (2018). Also, beta estimates for freight railroads are much higher than those for regulated electric or gas networks.

195. Given that the STB is determining the rate of return for a different industry, the most relevant comparison is probably the MRP. The AER's MRP is slightly lower than the STB's (6.1% vs 6.9%).

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[101] While the Blume adjustment increases the betas for FERC's transmission comparable companies, the magnitude is getting smaller as raw betas have increased over the past year. Raw betas are consistent with the upper end of the AER estimated betas. We also note that the use of Blume adjusted betas decreases the betas used in natural gas pipeline cases as such betas consistently are above 1.

5. ARERA

a. Calculating the figures in Table 4

196. For ARERA we report the most recent WACC decision in Table 4 (the decision for gas distribution from 2019). We selected gas distribution because this decision is the most recent and therefore closest in time to the AER's Energex decision. ARERA reports a real pre-tax WACC, shown in bold in Table 4. ARERA reports a real cost of equity and a real cost of debt, so we can calculate a real vanilla WACC directly.

b. Comparing with the AER determination for Energex

197. We show a real vanilla WACC for Energex of 2.46% in Table 4, whereas we show a real vanilla WACC for ARERA of 4.27%. The difference is due to the cost of equity: the AER's real cost of equity is 2.42% whereas ARERA's is 5.77%. Although the cost of debt is similar (2.49% vs 2.39%), the difference in the cost of equity is really caused by the different risk free rate assumptions, which are also offset by different debt premiums. The key difference here is that AER uses a negative real risk-free rate. While negative interest rates are observed in several regions of the world, it is difficult to believe that a negative risk-free rate can be sustained for several years and that, in combination with a historical arithmetic average MRP, it fully reflects current expectations from investors.[102] In contrast, ARERA operates with a lower bound on the real risk-free rate of 0.5%.

198. The equity premium for AER and ARERA are similar (3.66% vs 3.88%), but the AER's real risk free rate is –1.24% whereas ARERA's is +1.89% (the latter figure includes a country risk premium of 1.39%). The AER's debt premium is 3.73% whereas ARERA's is 0.5%.

6. NZCC

a. Calculating the figures in Table 4

199. For New Zealand we report figures from the most recent determination (for electricity distribution, from 2019) in Table 4. The NZCC reports a nominal vanilla WACC, shown in bold in Table 4. We make several adjustments to this figure to make it more comparable with the AER's figures.

200. The NZCC reports a mid-point estimate of the rate of return, and then moves to the 67th centile to reflect its judgement that the costs of setting a rate of return that is too low are higher than the costs of setting a rate of return that is too high. The NZCC reports this 67th centile rate of return, but does not report the corresponding

102 We note that commercial data providers such as Duff & Phelps "normalize" the risk-free rate when used in combination with a historical average MRP. Source: Duff & Phelps, "2019 Valuation Handbook: US Guide to Cost of Capital," Chapter 3. Duff & Phelps explain that they use two methods to determine the normalized risk-free rate: (1) average of long periods of observed yields on 20-year US government bonds and (2) the sum of a forecasted real yield on 20-year government bonds plus an inflation forecast.

underlying parameters on which it is based (rather, it only reports the parameters corresponding to the mid-point estimate).

201. In principle, all of the parameters (risk-free rate, equity beta, MRP, debt premium) are uncertain. However, we think that the risk-free rate and debt premium are probably more certain than the equity beta and the MRP. We therefore use the risk-free rate and debt premium corresponding to the mid-point rate of return estimate, and we adjust upwards both the equity beta and the tax-adjusted MRP (both by the same percentage) so that we calculate the NZCC's 67th centile rate of return. Specifically, in order to produce the NZCC's 67th centile rate of return, we need to multiply both the equity beta and the tax-adjusted MRP by 1.09 (from 0.60 to 0.65, and from 7.00% to 7.61%).

202. We also adjust the cost of equity to reflect the fact that the cost of equity used by the NZCC is adjusted for investor taxes, as we explained above.[103] We convert the NZCC's tax-adjusted MRP parameter to an unadjusted figure, and we remove the tax adjustment to the risk-free rate.[104] The cost of equity to the utility (corresponding to the 67th centile) is 5.76% and the overall return demanded by equity investors (including the value of franking credits) is 5.87%.

203. Finally, we also remove the explicit allowance for debt raising costs which the NZCC includes in its cost of debt estimate.

204. After making these adjustments we find a nominal vanilla WACC of 4.55%. This is very close to the NZCC's reported 4.57% because the impacts of investor taxes and debt raising costs are similar and offsetting.

205. Finally, we also report a real vanilla WACC of 2.56% by adjusting for inflation.

b. Comparing with the AER determination for Energex

206. We think that the best comparison between the AER and NZCC determinations is the real vanilla WACC of 2.46% for the AER vs 2.56% for the NZCC. These results are very close and both regulators have very similar risk free rates (1.03% vs 1.22%). However, there are also offsetting difference in debt and equity premiums. The AER's debt premium is 3.73%, whereas the NZCC's is 1.60%. The difference in equity premiums is the other way (3.66% vs 4.75%).

207. The AER's equity beta and MRP estimates are both below the NZCC's (10% and 20% respectively). In addition, the AER has a much higher gearing assumption than the AER (60% vs 42%).

103 See paragraph 35.

104 The NZCC's cost of equity is risk-free rate x (1 – investor tax rate) + equity beta x TAMRP (see paragraph H2.46 of the 2016 consolidated reasons paper). TAMRP = MRP + risk-free rate x investor tax rate (see footnote 1033 of the 2016 consolidated reasons paper).

7. Ofgem

a. Calculating the figures in Table 4

208. Ofgem reports a real vanilla WACC of 2.88%. However, this figure does not directly relate to Ofgem's underlying CAPM estimate. First, Ofgem adds 0.1% to its CAPM-based midpoint estimate of the cost of equity to reflect "cross-checks" with other evidence. Second, Ofgem subtracts 0.5% from its cost of equity estimate to reflect "expected outperformance". We think that this means Ofgem anticipates that utilities will be able to reduce their expenses, and/or earn net incentive payments, equivalent to an additional return to equity of 0.5%. However, rather than adjusting the opex building block or making its incentive schemes symmetrical (with an expected payout of zero), Ofgem is proposing to reduce its authorised rate of return by an equivalent of 0.5% on the cost of equity. Since this reduction has nothing to do with the cost of equity, we remove the adjustment from Ofgem's figures.[105]

209. Ofgem's real vanilla WACC of 2.88% is based on an underlying authorised equity return of 4.3%. We recalculate a real vanilla WACC of 3.08%, based on Ofgem's cost of equity estimate of 4.8%. As we did with the NZCC figures, we have also calculated a notional equity beta and MRP figure which correspond to Ofgem's 4.8% cost of equity. These figures are Ofgem's reported equity beta and MRP figures multiplied by an adjustment factor of 1.01.

b. Comparing with the AER determination for Energex

210. We estimated a real vanilla WACC of 2.46% for the AER and we estimated a real vanilla WACC of 3.08% for Ofgem. The AER's risk-free rate is lower than Ofgem's (−1.24% vs −0.75%). The AER's debt premium is larger than Ofgem's and the AER's equity premium is much smaller (3.73% vs 2.68% for debt, and 3.66% vs 5.55% for equity).

211. The AER's MRP and equity beta are both about 20% below Ofgem's (note that a small amount of this difference is due to Ofgem's "cross checks", which we assumed to correspond to upwards adjustment to equity beta and MRP).

105 Ofgem said: "In effect, our updated working assumption for the allowed return on equity remains 0.5% less than our current best estimate of the cost of equity. In any case however, this means that investors can expect to achieve 4.8% returns on equity. Our current view is that 4.3% will be earned through the allowed return on equity and 0.5% will be earned through incentives. By extension, if we are persuaded, in light of the additional information to which we refer, that expected outperformance is less than 0.5%, then we would set the allowed return closer to the cost of equity. In either case, investors should, based on our current view, expect 4.8% return on equity." (Ofgem's RIIO 2 finance decision, paragraph 3.302.)

8. Ofwat

a. Calculating the figures in Table 4

212. Ofwat reports a real vanilla WACC of 2.96%. We make an adjustment to remove Ofwat's debt raising cost assumption from the cost of debt, and calculate a corresponding real vanilla WACC of 2.90%

b. Comparing with the AER determination for Energex

213. We estimated a real vanilla WACC of 2.46% for the AER and we estimated a real vanilla WACC of 2.90% for Ofwat. The difference is primarily due to AER having a lower equity premium than Ofwat (3.66% vs 5.58%), and in turn this is caused by AER having lower equity beta and MRP estimates than Ofwat.

9. Observations

214. Based on the discussion in the individual sub-sections above, we make the following observations:

a. The AER's equity beta estimate is below all of the other regulators. As the Australian market index today is quite diverse (as is that of the US, UK, and the EUROSTOXX used in the Netherlands), we believe it could partly be an effect of the longer window. We note that the Australian study on betas found that the betas using windows of 1-5 year was higher than the "longest sample" with a range of 0.49–0.88 for the last five years.[106] At the same time, we observe increasing electric and gas utility betas in the US.

b. The AER's debt premium is above all of the other regulators albeit the cost of debt in comparable to that of STB, ARERA, NZCC and Ofwat. We understand that this is likely to reflect the fact that the AER is in the process of transitioning to the trailing average methodology, so that there is currently a significant weighting on some higher-cost debt estimates.

c. The AER's MRP estimate is below those of other regulators with recent determinations but above those of the ACM and ARERA (determinations in 2016 and 2015 respectively). The key difference here is that ACM and ARERA put substantial weight on the historical geometric average.

[106] AER Staff Beta Analysis, June 2017, Figure 1, p. 10 and p. 189.

III. Conclusion

215. We have documented the rate of return methodologies used by different regulators. There are of course some aspects that are similar across several regulators, and other aspects that are unique to one regulator or another. Overall, we would not characterise the different regulators as having chosen one rate of return method or another. All of the regulators determine an authorised rate of return by estimating the cost of capital supplied by investors. Rather, in designing the overall rate of return methodology, or in considering each component of the rate of return, there are different approaches that can be taken.

216. We do not think that that it is particularly helpful to characterise one regulator's rate of return methodology as better than another. However, by looking across the methods used we can identify important differences, and where there are differences we can suggest which approach we think works best.

217. In particular, when we compare the AER's method with those of the other regulators, we observe important differences in four related areas concerning the cost of equity. We think that these observations indicate some areas in which the AER's approach, in our view, is not as effective as the approach of other regulators. These areas include:

    a. incorporating forward-looking evidence into the cost of equity;

    b. use of multiple models for estimating the cost of equity;

    c. how often to update the cost of equity; and

    d. equity beta estimation.

218. We expand on each of these points below.

219. While the different regulators apply a variety of approaches to the cost of debt, we think that the AER's approach, which is very similar to that used by Ofgem and Ofwat, is a good one. The trailing average approach should better reflect the cost at which the utilities are able to borrow.

1. Incorporating forward-looking evidence into the cost of equity

220. The AER, like most of the reviewed regulators, relies on a MRP that is essentially backwards-looking.[107] The advantage of the approach is that it makes the parameter stable and predictable, but it may fail to capture recent developments in the market. For example, recent international evidence indicates the MRP one year out (including that of Australia) increased by a non-trivial amount in March 2020 as

[107] The AER reviewed additional information but eventually choose a historical measure of the MRP.

Covid-19 became a concern.[108] In contrast, some regulators incorporate at least some forward-looking evidence into their MRP estimates. For example, the NZCC incorporates both historical and forward-looking evidence into its MRP assessment, and the FERC uses a purely forward-looking MRP estimate based on a DCF approach.

221. The AER combines its MRP estimate with the current yield on a ten-year bond. That yield is currently negative in real terms. We think that there is a significant probability that negative real rates will not be maintained over an extended period. Although current yields of risk-free debt are below the AER's inflation estimate, and have been for an extended period, it is difficult to reconcile a negative real interest rate with finance theory. We also think that it is unlikely that the equity premium and the debt premium could be as similar to each other as implied by the AER's current figures. We note that ARERA, for example has implemented a "floor" on the real risk free rate of 0.5%. Other possibilities would be to take into account forecasts of the risk free rate later in the period (or to update the cost of equity parameters more frequently, as we discuss below).

222. We think that it is beneficial to incorporate at least some forward-looking evidence into the cost of equity determination.

2. Using multiple models

223. All the regulators except for the FERC and the STB rely on a single model to estimate the cost of equity (the CAPM). While some do incorporate various cross-checks on the CAPM results or individual inputs to the CAPM, we think that it is better to use more than one model, because different models make use of different inputs and thus provide different information relevant for estimating the cost of equity. The FERC and STB put equal weight on the CAPM and the other models. This contrasts with the other regulators, including the AER, which place zero weight on the DCF model. We think that it is better if the weight on the CAPM estimate is strictly less than 100%. Specifically, the CAPM relies on measures of systematic risk (company-specific), risk-free rates and MRP (market wide), while the DGM relies on dividends, stock prices, and growth rates, which are company specific (although some include GDP growth). Thus, these models look at different parts of the total information available in the market and contribute different insights. The DGM is predominantly forward-looking and the CAPM (with a historic MRP) relies predominantly on historic data that are used to infer the

[108] Source: Bloomberg data. Bloomberg calculates the forward-looking MRP using a multi-stage DGM using the companies in the country's stock index and weighting the companies by their market share. The multi-stage DGM converges the company-specific growth rates based on analysts' forecasts to the forecasted GDP growth over a period of 10 years.

expected return. Both contribute to the understanding of investors required return but from different angles.[109]

224. Since the DCF is inherently forward-looking, it is particularly beneficial to put some weight on this model if the CAPM implementation is purely backwards-looking.

3. How often to update

225. The different regulators update their cost of equity estimates with different frequencies, and some update all of the parameters together while others update some parameters for every revenue determination and not others. Clearly there is a trade-off in that frequent updating of the rate of return is potentially expensive in terms of resources for the regulator and the regulated utilities, while infrequent updating means that market conditions (and thus the cost of capital) could have changed and this will not yet have been reflected in the rate of return determination. Some regulators determine revenues for multiple utilities at the same time.

226. We think that the AER's current practice of four years between rate of return determinations, combined with not reflecting updates in revenues until the beginning of the next revenue determination, means that the rate of return updates are slower than would be ideal.

227. However, in addition to this trade-off around the frequency of updating, we also think that there are important interactions between the CAPM cost of equity parameters, such that it may create inconsistencies—and thus an inaccurate result—if some parameters are updated but others are not. When estimating a forward-looking MRP, the measured MRP commonly increases as the risk-free rate declines and vice versa. Similarly, because the equity beta is estimated using market data, the beta estimate will typically be affected by changes in market conditions. We therefore think that it is problematic to change one of the CAPM inputs without updating the cost of equity estimate as a whole.

228. We do not think that it is possible to design a "formulaic" method for estimating the cost of equity, such that all discretion is removed. Thus updating the cost of equity requires a full rate of return proceeding.

229. The AER (and Ofgem) already adjusts revenues annually for changes in the cost of debt. Ofgem is proposing to do the same thing for the impact of changes in the risk free rate on the cost of equity. As we explained above, we find Ofgem's approach has some significant disadvantages because it is likely that factors causing a change in the risk free rate might also cause MRP and beta to change. Similarly, we think that the practice of using an "on the day" risk free rate estimate together with an MRP and equity beta that are not updated is also problematic (this is the AER's

[109] We note that there are other models that look to different types of information; e.g., risk premium models (considering earned or allowed returns as well as bond yields) and Fama-French models (considering size and value premia in addition to MRP).

approach, also used by the NZCC). We think that if capital market conditions change enough to cause a significant movement in the risk free rate, the cost of equity as a whole should be redetermined, not just the risk free rate component.

230. However, we do not see any problem associated with reflecting a change in the cost of equity in revenues without having a full-blown revenue determination. We note that ARERA already does this, and AER and Ofgem do this for the cost of debt. In particular, we do not see any connection between the cost of equity and other building blocks, such that the cost of equity would have to be determined at the same time as the other building blocks. If the cost of equity is updated, there will be a consequential update required to the tax building-block, but we would expect this to be straightforward.

231. Taken together, therefore, we think these observations suggest that the AER's current practice of determining the rate of return separate from the revenue determination is beneficial, but that in three areas the practice of other regulators has advantages: first, the period between the AER's rate of return determinations is too long (particularly given that new parameters do not influence revenues until after the next revenue determination); second, it would be better to determine all of the cost of equity parameters in the same rate of return proceeding, including the risk free rate, with no updating of any rate of return parameters in a separate revenue determination; and third, it would be better to reflect the new cost of equity results in revenues immediately, without waiting for the start of the next revenue determination.

4. Estimating beta

232. The AER relies on a beta estimate that "place[s] the most reliance on the data from the longest available period" and also had some regard to a five-year window. [110] That is in contrast to most regulators that rely on a shorter horizon. Using a five-year window (or longer) risks that AER's beta measure fails to give sufficient weight to current financial conditions. We recognize that there is a trade-off between betas being stable and current, but find that an estimation window of 2-5 years using daily or weekly data provides sufficient statistical reliability and the impact of switching to a shorter estimation window can be material.[111] To the degree that the AER finds that the shorter estimation window means that the total amount of data is limited, the addition of international comparators instead of lengthening the estimation window and risking the incorporation of out of date data merits consideration. We note that a number of regulators (ACM, ARERA, FERC, NZCC) include non-local companies. As noted above, this approach requires careful consideration of both the comparability of the added international comparators and the market in which they operate. Given such careful consideration of the comparability of companies and financial markets as well as the lack of substantial exchange rate risk, we find the

110 AER, "Rate of Return Instrument: Explanatory Statement," December 2018, p. 99 and 189.

111 See, for example, Jonathan Berk & Peter DeMarzo, "Corporate Finance," 3rd Edition, 2014, p. 407 and Villadsen et al., "Risk and Return for Regulated Industries," Academic Press, 2017, pp. 74-76.

inclusion of additional comparators from international markets beneficial—especially when the local market has a limited number of comparators.

IV. Appendix

A. The Australian Energy Regulator

1. Regulatory framework

233. The Australian Energy Regulator (AER) determines the revenues for energy networks in Australia (with the exception of Western Australia). It regulates revenues for electricity distribution and gas distribution networks, for electricity transmission networks, and for some natural gas transmission pipelines. The businesses that the AER regulates are mostly investor-owned but some are wholly or partly owned by state governments.

a. *Objective*

234. The AER's overarching objective is to contribute to achieving the NEO/NGO: "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system." and "to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."[112]

235. The regulatory framework is set out in a combination of primary legislation and detailed "Rules" which set out both the obligations of the regulated businesses and the AER.[113] The Rules are quite detailed: for example, the AER is required to publish a "framework and approach paper", the business is required to file a "regulatory proposal", and the AER is required to make various draft and final decisions about the proposal—both the need for and the timing of all of these steps is set out in the Rules.[114] Any market participant, including the regulated business, the AER, large customers, and various customer representative bodies can propose a change to the Rules. Proposed changes are assessed by the Australian Energy Market Commission.

236. In addition to the Rules themselves, there are also various other formal documents referred to in the legislation and/or the Rules. For example, the Rate of Return Instrument, discussed below, is one such.[115]

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[112] National Electricity Law, cl. 7; National Gas Law, cl. 23. See also "National Energy Objectives" at https://www.aemc.gov.au/regulation/regulation

[113] For example, Chapter 6 of the National Electricity Rules deals with the economic regulation of distribution services.

[114] See *National Electricity Rules*, Rules 6.8 to 6.14 in relation to electricity distribution. There are equivalent clauses for electricity transmission and broadly equivalent provisions in the National Gas Rules.

[115] NEL, Part 3, Division 1B and NGL, Chapter 2, Part 1, Division 1A.

237. The AER determines the revenue that the various regulated businesses can collect from providing regulated services. The revenue determinations cover a five-year period, with revenues over the five-year period set equal to a forecast of the efficient costs of providing the regulated services. The outcome of the revenue determination is a cap on the revenue that may be collected for each year of the upcoming period, with the cap expressed in real terms. Each year during the five year period the revenue cap is converted into a nominal figure by applying an adjustment for actual inflation. Thus, for example, if inflation actually experienced is higher than that anticipated in the revenue determination, the dollar amount of revenue that the business can collect will be higher.[116]

238. As part of the revenue determination, the value of the regulatory asset base will be "rolled forward" from the opening value approved at the start of the prior period. This rolling-forward takes into account actual capital expenditures (and depreciation forecast in the prior revenue determination), subject to an ex-post efficiency review if actual capex is greater than the approved forecast.[117]

239. In addition to the basic revenue determination described above, there are also various additional items or adjustments made during the five year period. For example, there are adjustments which aim to "equalize the incentive" for the business to reduce its costs: these adjustments each year depend on the difference between forecasts and actuals (both capex and opex) in the prior five years, and aim to equalize the financial benefit to the regulated business of achieving either opex or capex savings, and of achieving savings earlier or later in the five-year period.[118]

240. The AER's revenue determinations are not subject to appeal or review on the merits of the decision.[119]

241. The AER's rate of return methodology is set out in the Rate of Return Instrument. The Rate of Return Instrument is binding on both regulated businesses and the AER. Notably, the Rate of Return Instrument must apply in the same way to all

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116 See, for example, *Regulatory Treatment of Inflation—Final Position Paper*, AER (December 2017), pp. 9–10.

117 The AER can use either forecast or actual depreciation, but typically uses forecast. See, for example, *Better Regulation—Explanatory Statement, Capital Expenditure Incentive Guideline for Electricity Network Service Provider*, AER (November 2013), chapter 3.

118 See *Better Regulation—Explanatory Statement, Capital Expenditure Incentive Guideline for Electricity Network Service Provider*, AER (November 2013) and *Better Regulation—Explanatory Statement, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, AER (November 2013).

119 The AER's decisions are subject to judicial review, but judicial review would not assess the merits of a decision, only whether the decision was lawful. Prior to 2017 the AER's decisions could be appealed to the Australian Competition Tribunal (see *Competition and Consumer Amendment (Abolition of Limited Merits Review) Bill 2017—Explanatory Memorandum*, Parliament of Australia).

businesses,[120] and the methodology it contains must not leave room for the exercise of any discretion (for example, it "cannot include different methodologies or a band of values from which the AER could choose in applying the instrument").[121]

242. The legislation provides that "The AER may make an instrument only if satisfied the instrument will, or is most likely to, contribute to the achievement of the national electricity objective to the greatest degree."

b. Timing and sequencing

243. The various businesses regulated by the AER each have a timetable for the five-yearly cycle of revenue determinations.[122] The rate of return is a component of the revenue determination for each business. While some of the underlying inputs (for example, rate base at the start of the period, and forecast rate base each year during the period) are determined for each business in each individual revenue determination, the methodology for calculating a rate of return, and the rate of return parameters (cost of debt, cost of equity, gearing assumption and so on) are determined in a separate proceeding once every four years.[123] Once determined, the rate of return methodology and the associated rate of return parameters will be applied to the revenue determination for each business over the subsequent four year period. Thus, for example, recent determinations and those that will be made up through 2022 have used and will use the rate of return parameters and methodology determined in the most recent rate of return review (in 2018).

244. The parameters are set out in the Rate of Return Instrument, which must be reviewed and replaced with a new instrument every four years. The process for making the instrument, including consultation and involving both an expert panel and a consumer reference group, is set out in legislation.[124] The methodology behind the parameters is explained in the associated Rate of Return Instrument Explanatory Statement (and associated documents).

245. The most recent AER decision on the rate of return was the 2018 Rate of Return Instrument, published in December 2018.

2. Rate of return

a. The overall rate of return

246. The AER sets a nominal vanilla WACC, with a separate tax allowance. However, the mechanics of the revenue determination are such that an estimate of expected

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120 There is scope for one instrument to apply to gas and a separate one to apply to electricity, but currently the same instrument applies to both sectors.

121 See *National Electricity Law*, section 18J.

122 Within a particular state, the individual electricity distribution businesses tend to have the same timing for their revenue determinations, but otherwise the cycles are not aligned.

123 See *National Electricity Law*, sections 18F–18W.

124 See *National Electricity Law*, sections 18K–R.

inflation is also an input to the calculation of revenues and, in effect, the revenue determination targets a real rate of return on investment. The method for determining the inflation forecast is not part of the Rate of Return Instrument.

247. Table 6 below summarizes the parameters contained in the 2018 instrument.

Table 6
AER 2018 rate of return instrument

Parameter		Value/method
Gearing	[1]	0.6
Equity beta	[2]	0.6
Market risk premium	[3]	6.10%
Risk free rate	[4]	on the day
Cost of debt	[5]	trailing average
Term for cost of debt	[7]	10 years
Credit rating	[8]	BBB+ benchmark (1/3 weight on A, 2/3 on BBB)
Gamma	[9]	0.585

Sources:
2018 Rate of Return Instrument

248. The AER's overall approach is to estimate the cost of debt on a trailing average basis over 10 years, targeting a 10-year BBB+ corporate bond yield. The rate of return will be updated annually (and authorised revenues recalculated annually) to reflect changes in the cost of debt. However, the AER is still in the process of "transitioning" from the prior approach, so effectively there is currently a 50% weighting on the trailing average (back to 2015) and 50% weighting on the previously-determined cost of debt from 2015.[125] Over time, the number of years in the trailing average increases until it is a full historical trailing average with a 10 year rolling window. The cost of equity is estimated using the CAPM, using an "on the day" estimate of the risk-free rate (10 year government bonds). The cost of equity is estimated only once for each utility at the start of the revenue determination period, but a new risk-free rate estimate is made for each utility. The value of the MRP and equity beta is not re-estimated.[126]

249. The AER's estimate of the MRP is adjusted to reflect the value of imputation tax credits (i.e., the MRP represents the additional returns demanded by investors in Australian equities over the risk free rate, including both the returns that come from owning equities (dividends and capital gains) and the value of franking credits that

125 The start of the transition period varies between utilities, based on the date of the first revenue determination after 2013 (which was 2015 for Energex).

126 AER, *Rate of Return Instrument – Explanatory Statement*, pp. 13–17.

can be set against investors' tax liability). The value of the imputation tax credits depends on a parameter ("gamma") which the AER determined to be 0.585.[127] Gamma is also an input to the AER's tax building block, as we explain below.

250. In Table 7 below we summarise the AER's rate of return decision for Energex, one of the electricity distribution businesses in Queensland.[128]

Table 7
AER's rate of return decision for Energex

Parameter	Value / method	Note
Gearing	0.6	Same as 2018 Instrument
Equity beta	0.6	Same as 2018 Instrument
Market Risk Premium	6.10%	Same as 2018 Instrument
Risk free rate	1.03%	20 business days ending 20 February 2020
Cost of equity	4.69%	
Cost of debt	4.76%	Trailing average. Applies to 2020-21 only, will be updated annually
Nominal Vanilla WACC	4.73%	
Expected inflation	2.27%	

Sources
FINAL DECISION, Energex Distribution Determination 2020 to 2025, Attachment 3 Rate of Return, AER (June 2020), Table 3.1.

b. Cost of debt

251. The "trailing average" approach to determining the cost of debt means that, for each year of each revenue determination, the current cost of debt is determined using the "on the day approach". The AER wants to target a BBB+ 10 year corporate bond yield, but since there is no such index available, it instead uses a 1/3 2/3 weighted average of the yields on A-rated and BBB-rated bond indexes. The yield data is averaged across three providers (Bloomberg, Thomson Reuters and the RBA). The authorised cost of debt is then a trailing average of the prior 10 "on the day" estimates—i.e., notionally the AER assumes that the business issues 10-year debt and that 10% of the debt matures each year. The business can propose the averaging windows (within limits set out in the instrument).

252. The instrument sets out in some detail how the various yields are to be calculated. Note that there are transitional issues associated with the fact that the trailing average approach for the cost of debt has been in use for less than 10 years. We have not described how these issues are addressed, but in effect this means that the trailing average currently extends only back to 2015, with the years prior to 2015 effectively replaced by the cost of debt determined by the AER at that time (using an "on the day" approach). Over time, as additional years enter the averaging window, the weight on the historical averages will increase and the weight on the AER's prior methodology will decrease.

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127 *Ibid.*

128 AER, *FINAL DECISION, Energex Distribution Determination 2020 to 2025, Attachment 3 Rate of Return*, (June 2020), Table 3.1.

253. The 10 year term is consistent with the available evidence on actual terms, which was that the term tends to be at least 7 years.[129] The choice of a BBB+ benchmark is also consistent with actual credit ratings observed for comparator firms.[130]

c. Cost of equity

Equity beta

254. The 0.6 equity beta assumption comes from examining returns for a variety of individual comparators and different portfolios of comparator firms, different time periods, and weighting (equal vs market- value). The estimates: use Ordinary Least Squares; weekly returns; the Brealey–Myers formula to de- and re-lever;[131] consider both raw and re-levered estimates; do not apply a Blume or Vasicek adjustment.[132]

255. The AER determined the equity beta of 0.6. The AER stated that it "gave most weight to empirical estimates of relevant Australian energy network businesses" and it "considered: conceptual analysis of the risks of the regulated energy network businesses relative to the market portfolio; empirical estimates of international energy network businesses; and the theoretical underpinnings of the Black CAPM.".[133] It did not adjust the estimate to reflect "low beta bias" or the "Black CAPM".[134]

256. The same 0.6 equity beta is applied to all businesses (gas and electricity, transmission and distribution). The AER considers that, conceptually, "equity beta for regulated gas and electricity firms are likely to be similar because they are regulated natural monopolies with similar regulatory frameworks which limits systematic risk exposure" [135] and that international evidence of possible differences was not persuasive.

Market Risk Premium

257. The MRP is 6.1%, which is the excess of historical equity returns over the 10 year government bond for the period 1988 to 2017.[136] Note that the estimate of historical equity returns requires assumptions to be made about the value of imputation tax

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129 AER, *Rate of Return Instrument – Explanatory Statement*, pp. 278-9.

130 AER, *Rate of Return Instrument – Explanatory Statement*, pp. 279.

131 Including an assumption that the debt beta is zero (see *AER Staff Beta Analysis June 2017*, p. 17).

132 AER, *Rate of Return Instrument – Explanatory Statement*, p. 97.

133 AER, *Rate of Return Instrument – Explanatory Statement*, p. 142.

134 *Ibid.*, pp. 195–6.

135 *Ibid.*, pp. 175.

136 AER, *Rate of Return Instrument – Explanatory Statement*, p. 91.

credits, and the AER's 6.1% figure reflects measuring historical equity returns to incorporate the value of franking credits assuming gamma is 0.585.[137]

258. The AER considered a range of other evidence, but ultimately decided to rely on the figure of 6.1%, which is the historical excess return ("HER") from the 1988 to 2017 period calculated using an arithmetic average. The AER said:[138]

As set out above we consider a range of evidence in determining our MRP estimate. We give evidence from the HER the most weight in our estimation of the MRP. We consider data from HER shows:

- *The range given by arithmetic averages for different sample periods is 6.0 per cent to 6.6 per cent. The most recent, 30 year, period produces an estimate of 6.1 per cent and is most likely to reflect current prevailing conditions.*

- *Geometric averages indicate a range of 4.2 to 5 per cent. We place more weight on arithmetic returns however these geometric averages indicate the forward looking MRP value is most likely to be towards the bottom of the range given by the arithmetic averages. The most recent, 30 year, period produces an estimate of 4.6 per cent.*

We derive a point estimate of 6.1 per cent from HER evidence. The range of other evidence to which we give less weight to indicate that:

- *The current volatility is lower than the historical average and has been for a sustained period of time. Expert advice suggested it is unlikely that the MRP is relatively high when the implied market volatility is low. The low volatility supports an MRP below long run historical average.*

- *Survey evidence supports a broad range of MRPs, however the most common value for mode, median and mean from surveys over the past 3 years is 6 per cent.*

- *Low credit spreads and average dividend yields give us no reason to move our point estimate from the HER result of 6.1 per cent.*

- *Results from our construction of the DGM arrives at a range of MRP estimates from 6.52 to 8.02 per cent, which upon applying sensitivity*

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137 AER, *Rate of Return Instrument – Explanatory Statement*, p. 221.

138 AER, *Rate of Return Instrument – Explanatory Statement*, p. 94, footnotes omitted.

> *analysis extends to 5.96 to 8.59 per cent which suggest an MRP higher than 6.1 per cent.*
>
> *In this final decision, having considered the utility and informative value of the other evidence, we are not persuaded to adjust our HER estimate to which we give most weight in selecting our MRP point estimate of 6.1 per cent. Based on the reasons above we note that our confidence in the informative value of the DGM based MRP estimates have diminished. In our 2013 Guidelines, we used our HER estimate of 6.0 per cent as the starting point and moved our estimate up based on the direction of the other evidence, particularly the DGM evidence. In this final decision we are not satisfied that such an upward adjustment is justified on the basis of the information available to us.*

Risk free rate

259. The "on the day" approach to the risk free rate means that for any particular revenue determination, the risk free rate is estimated from the yield on 10-year government bonds at the time of the determination. The business can propose the averaging windows (within limits set out in the instrument, including that the averaging period must be between 20 business days and 60 business days in length).[139]

260. In explaining its decision to use a 10-year bond, the AER said "Our final decision is to maintain use of a 10 year term for the risk free rate. We consider the use of a 10 year term will lead to an overall rate of return that will better contribute to the achievement of the NEO and NGO. We consider a 10 year term is consistent with the theory of the Sharpe-Lintner CAPM which is a single period equilibrium model, estimating the returns an investor requires over a long-term investment horizon. The 10-year term also reflects the actual investor valuation practices and academic works. We consider a reasonable argument could be made in support of a five year term. However, we found the evidence for this term to be less persuasive than that for a 10 year term."[140]

d. Gearing

261. The 0.6 gearing assumption is based on reviewing market evidence from comparator firms.[141]

[139] AER, *Rate of Return Instrument*, cl. 8a.

[140] AER, *Rate of Return Instrument – Explanatory Statement*, p. 126.

[141] *Rate of Return Instrument – Explanatory Statement*, chapter 4.

e. Treatment of tax and inflation

262. Tax paid by the utility does not form part of the AER's rate of return methodology, because the AER sets a vanilla WACC with an allowance for the contribution of regulated business earnings to corporate tax being an explicit part of the revenue determination.[142, 143] The AER's approach to tax is set out in separate policy documents.[144] The tax component of the revenue determination aims to forecast the tax that the business would pay if it otherwise matched the assumptions of the revenue determination. Thus, for example, the tax component assumes a gearing of 60%, and it takes into account some aspects of how tax liabilities are calculated (for example, it reflects accelerated depreciation provisions). However, not all aspects are reflected: for example, all entities are assumed to have a marginal tax rate equal to the corporate tax rate. This is not true for some investors (e.g., Australian superannuation funds (pension funds)).[145] Differences between assumed and actual tax paid are not trued up. Thus, for example, if a business has gearing higher than the AER's assumed 60%, it may have higher interest expense and thus lower tax liabilities (equally, if the business has a higher cost of debt than the AER's assumption, the tax liability would also be lower than the AER's assumption). This contrasts with Ofgem's approach.[146]

263. As discussed above, while the AER sets a nominal vanilla WACC, the mechanics of the revenue determination are such that the revenue determination targets a real rate of return on investment. The method for determining expected inflation is not part of the Rate of Return Instrument.

f. Imputation tax credits

264. Under the Australian tax system, equity investors which themselves pay Australian income tax are able to deduct from their own income tax liabilities an imputed amount of tax deemed already to have been paid on the income from which dividends were derived. As a result, the return on equity demanded by Australian equity investors is lower: these investors effectively receive not only dividend payments from their equity investments, but also a tax shield on their other sources of income. The effect of the imputation tax credit system is taken into account by reducing the size of the tax component of the revenue determination (i.e., it does not appear explicitly as a reduction in the cost of equity itself).

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142 In other jurisdictions, the regulator may "gross up" for tax, in which case the rate of return would be the regular after-tax weighted average cost of capital.

143 As noted above, the value of investor tax credits (gamma) does form part of the rate of return methodology because it influences how the MRP is estimated.

144 See, for example, *Review of Regulatory Tax Approach – Issues Paper*, AER (May 2018), p. 6

145 See *Review of Regulatory Tax Approach – Final Report*, AER (December 2018), p. 16.

146 See discussion in *Review of Regulatory Tax Approach – Final Report*, AER (December 2018), pp. 100–102.

g. Other factors

265. The AER includes an assumption about the cost of raising debt and equity capital in its revenue determinations. These amounts do not appear in the rate of return, rather the assumed cost of issuing debt is included in the operating cost component of the revenue determination, and the assumed cost of issuing equity is included in the forecast of capital additions (and hence ratebase).[147]

B. The Dutch Authority for Consumers and Markets

1. The regulatory framework

266. The Dutch Authority for Consumers and Markets (ACM) is the authority responsible for the regulation of energy transmission and distribution system operators (TSOs and DSOs) in the Netherlands. The Dutch government owns the Dutch gas and electricity TSOs, Gasunie Transport Services and Tennet. The DSOs—primarily held by Dutch provinces and municipalities—operate regional distribution networks. Altogether the ACM regulates 10 utilities.

a. Objective

267. The ACM has the responsibility to determine a regulatory method for the determination of tariffs, including the appropriate return on the invested capital. The legislator has entrusted the ACM with the task of establishing a method whereby the regulated companies have an incentive to act as efficiently as they would in a competitive market, with sufficient financial incentives for quality and efficiency improvement. In addition, when determining the method, the ACM must take into account the importance of security of supply, the importance of sustainability and the importance that network operators can realize a reasonable return on investments.[148] Government ownership of the transmission networks plays no role in the method determination.

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[147] See, for example, *Draft Decision – Jemena Gas Networks (NSW) Ltd, Access Arrangement 2020 to 2025 – Attachment 3 Rate of return*, pp. 7-10. Note that part of the AER's methodology is to consider whether the business would need additional equity to support its capital program, given the gearing assumption and the assumed ratio of dividends to earnings, and only if additional equity would be needed is an allowance made for the cost of issuing it.

[148] ACM's legal duties are established in the Dutch electricity and gas acts. See section 1 of the method decisions for the Dutch electricity and gas TSOs, Tennet and Gasunie Transport Services: (i) "Methodebesluit TenneT 2017-2021 Transport", dated 2 September 2016 (available at: https://www.acm.nl/nl/publicaties/publicatie/16169/Methodebesluit-TenneT-2017-2021-Transport); (ii) "Methodebesluit GTS 2017-2021", dated 23 February 2017 (available at: https://www.acm.nl/nl/publicaties/publicatie/16965/Methodebesluit-GTS-2017-2021).

268. Following consultations with the relevant stakeholders, the ACM publishes detailed "method decisions" for the regulated gas and electricity distribution and transmission at the beginning of the regulatory period.[149] The ACM determines five-year revenue controls based on a regulatory asset base indexed to inflation. The revenues allow the regulated network to recover capital depreciation and operating costs, including a return on the invested capital.

269. Also at the beginning of each regulatory period, the ACM applies a single, common methodology to determine the authorised rate of return for the four sectors (gas and electricity transmission and distribution).

270. Relevant stakeholders may appeal ACM's method decisions. A successful appeal may lead the ACM to revise its method decisions and to update its rate of return methodology for subsequent regulatory periods. As we discuss in more detail below, for example, a recent court ruling led the ACM to revise its 2017-2021 method decisions with respect to the peer group of companies used to estimate the beta, and subsequently to modify its rate of return methodology with respect to the liquidity tests to be applied in selecting peers.

b. Timing and sequencing

271. The ACM determines the WACC at the beginning of each regulatory period, and determines the revenue for the next five years at the same time.

272. The way the regulatory method is implemented requires the ACM to determine the WACC for two points in time: a WACC for the year before the start of the regulatory period and a WACC for the final year of the regulatory period. For example, in the latest method decisions for the 2017-2021 regulatory period, the ACM determined a WACC for 2016 and a WACC for 2021. Then, for the purposes of calculating the authorised revenues, the ACM interpolates between these figures to calculate the WACC for each year of the control, as we explain below.

2. Rate of return

a. The overall rate of return

273. The ACM calculates the authorised return based on a real pre-tax WACC. Appendix 2 of the method decisions provides a detailed description of the ACM WACC method.[150]

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[149] See, for example, the method decision for the Dutch electricity TSO, Tennet: "Methodebesluit TenneT 2017-2021 Transport", dated 2 September 2016 (available at:
https://www.acm.nl/nl/publicaties/publicatie/16169/Methodebesluit-TenneT-2017-2021-Transport).

[150] See ACM, Uitwerking van de methode voor de WACC, Annex 2 to the method decisions 2017-2021 (available at: https://www.acm.nl/nl/publicaties/publicatie/16199/WACC-methode-bij-de-methodebesluiten-2017-2021).

274. The ACM further distinguishes between existing assets, already included in the regulated asset base (the "existing capital"), and expansion investments (the "new capital"). The distinction is relevant only to the determination of the cost of debt and expected inflation.

275. Taken together, the two distinctions above result in four WACCs that the ACM must determine in its method decisions:

a. The WACC for existing capital for the year before the start of the regulatory period.

b. The WACC for existing capital for the final year of the regulatory period.

c. The WACC for new capital for the year before the start of the regulatory period.

d. The WACC for new capital for the final year of the regulatory period.

276. Table 8 below reports ACM's WACC calculations for the 2017-2021 regulatory period, as described Annex 2 to the method decisions 2017-2021.[151] As the Table shows, the four WACCs have the same nominal after-tax cost of equity, and differ only with respect to the cost of debt and inflation. The rate of return in each year is a weighted average of the WACC for existing capital and new capital, in proportion to the amount of existing versus new capital in the regulatory asset base.

[151] See ACM, Uitwerking van de methode voor de WACC, Annex 2 to the method decisions 2017-2021 (available at: https://www.acm.nl/nl/publicaties/publicatie/16199/WACC-methode-bij-de-methodebesluiten-2017-2021).

Table 8
ACM's Regulatory WACCs for 2017-2021

			Existing Capital		New Capital		Methodology
			2016	2021	2016	2021	
Gearing (D/A)	[1]	Annex 2, para. 79-81	50.0%	50.0%	50.0%	50.0%	Median gearing of comparators (46%).
Gearing (D/E)	[2]	[1]/(1-[1])	100.0%	100.0%	100.0%	100.0%	
Tax rate	[3]	Annex 2, para. 83-84	25.0%	25.0%	25.0%	25.0%	Current statutory corporate tax rate.
Risk free rate	[4]	Annex 2, para. 33	1.28%	1.28%	1.28%	1.28%	Average of German and Dutch 10-year government Bond yields over the past 3 years (2013-2015).
Asset beta	[5]	Annex 2, para. 59-69	0.42	0.42	0.42	0.42	Median asset beta of liquid comparators. Equity betas estimated against Eurostoxx TMI or S&P 500.
Equity beta	[6]	[5]x(1+(1-[3])x[2])	0.74	0.74	0.74	0.74	
Market Risk Premium	[7]	Annex 2, para. 45	5.05%	5.05%	5.05%	5.05%	Average of the geometric and arithmetic means of the historical Market Risk Premium for the Eurozone based on historical DMS data.
After-tax cost of equity	[8]	[4]+[6]x[7]	5.02%	5.02%	5.02%	5.02%	
Pre-tax cost of debt	[9]	Annex 2, para. 7-29	3.58%	2.29%	2.19%	2.19%	Average yield on a single A-rated utilities index plus 15 bp. Existing capital based on the staircase model (trailing average over the past 10 years). New capital based on forward looking estimate (average yiels over the past three years).
Nominal after-tax WACC	[10]	((1-[1])x[8])+([1]x(1-[3])x[9])	3.85%	3.37%	3.33%	3.33%	
Nominal pre-tax WACC	[11]	[10]/(1-[3])	5.14%	4.49%	4.44%	4.44%	
Inflation	[12]	Annex 2, para. 92-95	0.77%	1.42%	0.77%	1.42%	Average of historical and forecast inflation. Historical inflation calculated as average inflation in the Netherlands over the past three years. Forecast inflation calculates as either forecast inflation in 2016 for the 2016 WACC, or long-term inflation forecast for the 2021 WACC.
Real pre-tax WACC	[13]	Annex 2 Table 6, (1+[11])/(1+[12]) -1	4.3%	3.0%	3.6%	3.0%	

Sources:
ACM, Uitwerking van de methode voor de WACC, Annex 2 to the method decisions 2017-2021

b. Cost of debt

277. As explained above, the ACM's methodology for calculating the cost of debt distinguishes between existing capital and new capital.

Cost of debt for existing capital.

278. With respect to the existing capital, the ACM calculates the cost of debt based on the 'staircase model'. The staircase model assumes that network operators finance their existing investment with ten-year loans, and refinance 10% of their invested capital every year. Accordingly, the model calculates the embedded cost of debt of a hypothetical loan portfolio, 10% of which was issued in each of the past 10 years. (This is very similar to the AER's cost of debt methodology.)

279. While the cost of debt for existing capital is always based on a 10-year average, a different number of 'historical' years is used when calculating the WACC for the year before the start of the regulatory period (2016) and the WACC for the final year of the regulatory period (2021):

a. For the 2016 WACC, there are nine 'historical' years (2007-2015), and one 'forecast' year (2016).[152]

b. For the 2021 WACC, there are four 'historical' years (2012-2015), and six 'forecast' years (2016-2021). There is no subsequent truing up of the forecast years.

280. For the historical years (2007-2015), the methodology takes the average daily yield to maturity of comparable debt in any given calendar year. For the future years (2016-2021), the methodology takes the average daily yield to maturity of comparable debt over the three calendar years prior to the measurement date (that is, January 2013-December 2015).

281. As a measure of comparable debt, the methodology considers the yield on a utility index of 10-year bonds with a rating of A, which is consistent with the credit rating of Dutch network operators.[153] ACM's methodology further recognizes a 15 bps premium over the yield on comparable debt to cover the cost of issuing debt.

282. Table 9 below illustrates the calculation of the cost of debt for existing capital for the 2016 WACC and the 2021 WACC.

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152 Note that the estimate is based on full calendar years, so that 2016 was effectively a forecast year when ACM made the calculation in 2016.

153 The ACM methodology requires to use a broad index of bonds issued by European utilities with a credit rating of single-A. In practice, however, in its 2016 method decisions the ACM used Bloomberg's 'IGEEUB10' index, which covered bonds with BBB+/BBB- ratings. For the next regulatory period 2022-2026, the ACM has decided to use instead Bloomberg's 'C58310Y' index, which only includes single-A bonds by European utilities.

Table 9
ACM's Calculation of the Cost of Debt for Existing Capital

			Debt calc. for 2016 WACC	Debt calc. for 2021 WACC
2007	[1]	Historical	4.86%	
2008	[2]	Historical	5.32%	
2009	[3]	Historical	4.84%	
2010	[4]	Historical	3.88%	
2011	[5]	Historical	4.11%	
2012	[6]	Historical	3.09%	3.09%
2013	[7]	Historical	2.70%	2.70%
2014	[8]	Historical	2.02%	2.02%
2015	[9]	Historical	1.38%	1.38%
2016	[10]	Forecast	2.03%	2.03%
2017	[11]	Forecast		2.03%
2018	[12]	Forecast		2.03%
2019	[13]	Forecast		2.03%
2020	[14]	Forecast		2.03%
2021	[15]	Forecast		2.03%
Average yield	**[16]**	**Average [1] to [15]**	**3.43%**	**2.14%**
Issuance costs	[17]	Assumed	0.15%	0.15%
Cost of debt	[18]	Sum [16] to [17]	3.58%	2.29%

Notes:
[1] to [15]: Average yield of single A rated Utilities Index in the calendar year.
After 2015 average over 2013-2015 inclusive.

Cost of debt for new capital

283. With respect to new capital, the ACM's methodology takes the average daily yield to maturity of comparable debt over the three calendar years prior to the measurement date (that is, January 2013-December 2015). Therefore, the cost of debt for new capital will be the same for both the 2016 WACC and the 2021 WACC. Similar to the cost of debt for existing capital, the methodology considers the yield on a utility index of 10-year bonds with a rating of A, and adds a 15 bps premium to cover the cost of issuing debt. The cost of debt for new capital is thus 2.19% (average of the figures for 2013, 2014, 2015 plus the issuance cost).

c. Cost of equity

284. The ACM methodology calculates the cost of equity based on the CAPM, as the sum of a risk premium over the risk-free rate. The risk premium is calculated as the product of a market risk premium and the equity beta, which measures the non-diversifiable risk of the regulated company.

Equity beta

285. The Dutch TSOs and DSOs are not publicly traded. Accordingly, the ACM methodology estimates the beta for the Dutch energy networks based on the median asset beta of a 'peer group' of regulated energy networks that have similar systematic risk to the TSOs or DSOs in the Netherlands.

286. Historically, the ACM required a sample of at least 10 peers for a robust beta estimate. The peers should preferably operate in Europe and derive the majority of their revenues from energy transmission and distribution. However, it has become difficult to find 10 suitable peers. Accordingly, in its latest method decision, the ACM selected a sample of eight network operators, of which seven operating in Europe (Snam, Terna, Red Electrica, Enagas, Elia, REN, Fluxys) and one operating in the US (TC Pipelines).

287. The ACM methodology requires that the stocks of the peers are sufficiently liquid to obtain a reliable beta estimate. Historically, the ACM required that the shares of the candidate peers were traded on at least 90% of the days over the reference period ("the number of trading days test") and that the company had annual revenues of at least € 100 million ("the annual revenue requirement"). More recently, in response to a court ruling related to the liquidity of one of the peers,[154] the ACM abandoned these two criteria, and determined to apply a bid-ask spread threshold of 1% as its primary liquidity criterion.

288. The methodology specifies to estimate the equity beta of the individual peers using daily returns over a three-year period. The beta is measured against a broad Eurozone index for companies operating in the Eurozone, and broad national indices for companies operating outside of the Eurozone.

289. The ACM's methodology includes a series of diagnostic tests to assess if the equity beta estimates satisfy the standard conditions underlying the OLS regression. Historically, the ACM tested the OLS estimates for both heteroskedasticity and autocorrelation. In case of heteroskedasticity, the methodology required to use robust standard errors. In case of autocorrelation, the methodology required to perform use a Prais–Winsten regression instead of the OLS. More recently, the ACM decided to no longer correct for autocorrelation. Rather, the current methodology, which will be applied for the regulatory period 2022-2026, requires the OLS estimate of the beta parameter is used even in the presence of autocorrelation.[155]

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154 The court ruling was directly related to the peer group of companies used to estimate the beta for the Dutch network companies. The court found that one of the peer companies, Fluxys, did satisfy both the number of trading days and annual revenue requirements. However, the court determined that a high value of the bid-ask spread demonstrated that Fluxys' shares were illiquid.

155 Note that the OLS estimator of the beta is unbiased (not systematically too high or too low) and consistent (converges to the correct value) even in the presence of autocorrelation.

290. The ACM's methodology for the regulatory period 2017-2021 also considered two further adjustments.

a. The first adjustment is the Dimson adjustment, which accounts for the fact that share prices may react to news the day before or the day after the market index. The Dimson adjustment regresses a company's daily returns using the market index returns one day before and one day after as additional regressors. The Dimson-adjusted beta is given by the sum of the three coefficients calculated by the regression. The methodology selects the Dimson-adjusted beta estimate if it is statistically significantly different from the OLS beta estimate. The ACM will continue to apply the Dimson adjustment for the regulatory period 2022-2026.

b. The second adjustment is the Vasicek adjustment, an adjustment designed to avoid extreme estimates of the beta by 'pulling' beta estimates towards a 'prior expectation' of the beta for the sector. The Vasicek adjustment moves the observed beta closer the prior expectation by a weighting based on the standard error of the beta and the standard error of the of the overall market, so that values with lower standard errors will be given a higher weighting relative to the prior. The ACM will no longer apply the Vasicek adjustment for the regulatory period 2022-2026.[156]

291. Asset betas are calculated by un-levering the equity betas based on the average gearing[157] of the individual companies and applying the Modigliani and Miller formula.[158]

Market Risk Premium

292. The ACM's methodology calculates the MRP based on historical data published by Dimson, Marsh and Staunton (DMS) on the excess return of stocks over long-term bonds for the Eurozone economies over the period 1900-2015.[159]

a. The methodology calculates the MRP taking the simple average of the arithmetic and geometric means of the market risk premium for the Eurozone.

b. The MRP for the Eurozone is calculated as a weighted average of the MRP for individual Eurozone countries, using the current capitalization of each country's stock market as weights.

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156 We understand that this is because of the practical problem of establishing a prior expectation and the associated standard error.

157 The gearing is calculated based on the market value of equity and the book value of debt.

158 The formula assumes a constant value of debt and a debt beta of zero.

159 DMS report historical MRP for 10 Eurozone countries: Austria, Belgium, Finland, France, Germany, Ireland, Italy, Netherlands, Portugal and Spain.

293. The ACM's methodology also looks at evidence on the MRP from the dividend growth model as a 'sanity check' on the MRP estimate based on historical data.[160]

Risk free rate

294. The ACM methodology calculates the risk-free rate as the average yield on 10-year government bonds over the last three years in the Netherlands and in Germany.

d. Gearing

295. The ACM methodology estimates gearing for Dutch energy networks based on the median gearing of the same peer group it uses in the used in the estimation of equity beta. Consistent with the three-year reference period used to estimate the beta, the gearing of each comparator is calculated based on a three-year average of market-value gearing.

e. Treatment of tax and inflation

296. The ACM calculates the WACC in real pre-tax terms, by converting the nominal after-tax WACC to a real pre-tax WACC using the applicable tax rate and an estimate of inflation.

297. As a measure of the applicable tax rate, the ACM applies the statutory corporate tax rate in the Netherlands.

298. ACM's methodology for inflation requires a separate measure for the year before the start of the regulatory period and for the last year of the regulatory period. The methodology calculates inflation for both the 2016 WACC and the 2021 WACC as the average between:

a. Average historical CPI inflation in the Netherlands for the years 2013, 2014 and 2015. This component is the same for the 2016 WACC and the 2021 WACC.

b. Forecast inflation for the relevant WACC year. That is, forecast inflation for 2016 for the 2016 WACC and forecast inflation for 2021 for the 2021 WACC.

299. Table 10 below illustrates the calculation of inflation for the 2016 WACC and the 2021 WACC. The inflation assumption for the intermediate years is an interpolation between the 2016 and 2021 values.

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[160] For example, after the 2009 financial crisis, historical data indicated a decrease in the MRP, because realized returns of stocks over bonds were very low. But the DGM indicated that the MRP had if anything increased after the crisis. Hence, the results of the DGM indicated that, for this period, a downward reduction in the ERP was not justified, even though this is what the unadjusted historical data indicated.

Table 10
ACM's Calculation of Inflation for the 2016 WACC and the 2021 WACC

		Historical inflation [A] See note	Forecast Inflation [B] See note	Average [C] ([A]+[B])/2
2016 WACC	[1]	1.03%	0.50%	0.77%
2021 WACC	[2]	1.03%	1.80%	1.42%

Notes:
[A]: Average CPI inflation in the Netherlands in 2013-2015.
[B][1]: Forecast inflation in the Netherlands in 2016 from CPB.
[B][2]: Long term forecast inflation in the Eurozone from the ECB.

f. Imputation tax credits

300. Not applicable

g. Other factors

301. The ACM uses 15 bps as the premium to cover the cost of issuing debt.

C. The US Federal Energy Regulatory Commission

302. The Federal Energy Regulatory Commission (FERC) regulates all interstate natural gas pipelines and oil pipelines (that are common carriers) as well as interstate electric transmission. The businesses that the FERC regulates are typically investor-owned, although some are owned by municipalities or cooperatives. The remainder of this description focuses on electric transmission and natural gas pipeline regulation (the regulatory framework for electric transmission and natural gas pipelines is similar, whereas the framework for oil pipelines is significantly different).

303. Vertical integration is common (i.e., pipelines with affiliated shippers; transmission entities with affiliated generators and/or distribution and retail utilities). However, FERC regulates only the gas pipeline and electricity transmission segments, which have their own regulatory accounts.

1. The regulatory framework

a. Objective

304. The FERC's overarching objective is to "ensure that rates, terms, and conditions of jurisdictional services are just, reasonable, and not unduly discriminatory or preferential."[161] The FERC follows a cost-of-service ratemaking methodology - rates

[161] Federal Energy Regulatory Commission, *Strategic Plan 2018-2022*, September 2018. Available here.

are designed based on a regulated entity's cost of providing service including an opportunity for the regulated entity to earn a reasonable return on its investment.[162]

305. Under its cost-of-service ratemaking methodology, the FERC makes a determination on the maximum rates that can be charged by a regulated entity. The revenue requirement is based on operating costs (including maintenance costs), income and property taxes, interest on debt, depreciation to recover invested capital and a return on the capital invested. Typically there is no mechanism that adjusts either the rate base[163] or revenue for inflation.

306. The outcome of a FERC rate case is a set of "maximum rates"—i.e., the maximum prices that can be charged. For natural gas pipelines, a large majority of the total revenue comes from reservation charges (i.e., is independent of throughput). For electric transmission, the rates are generally capacity charges and volume with capacity charges being the largest proportion.

307. Although FERC regulates maximum rates for services, interstate natural gas pipelines frequently face competition and therefore may choose to discount their services in order to compete. Once maximum rates are set, a pipeline system is not permitted to adjust the maximum rates to reflect changes in costs or contract demand until new rates are approved by the FERC in a new rate case. In the case of electric transmission companies, the FERC relies on two methods (1) rates set in a rate case (like for natural gas pipelines) or (2) formula rates. Formula rates update rates annually using a pre-set formula which incorporates changes in operating expenses, administrative expenses, depreciation etc.[164] While interest rates may be updated, the authorised return on equity is not.

b. Timing and sequencing

308. There is no predetermined term for the regulatory period. If revenues no longer provide a reasonable opportunity to recover costs, a regulated entity can file with the FERC for a determination of new rates, subject to any moratoriums in effect. Similarly, subject to any moratoriums that have previously been agreed, customers may request a new rate case at any time. The vast majority of disputes are settled. Indeed, for gas pipelines, there have not been any fully litigated final decisions

[162] The FERC relies on ratemaking tools when competitive market conditions do not exist or competitive forces are inadequate to protect consumers. According to the FERC, it seeks to balance the need to protect energy consumers against excessive rates, while also "providing an opportunity for regulated entities to recover their costs and earn a reasonable return on their investments." *Id.*, page 1.

[163] "Rate base" is the term used by the FERC to describe the regulated asset base.

[164] FERC, "Staff's Guidance on Formula Rate Updates," July 17, 2014. The annual updates relies on the FERC's Form 1 is used by electric utilities regulated by FERC to file annual (and quarterly) financial information for the regulated entity following the accounting guidelines outlined by the FERC.

issued by the FERC within the last five years.[165] For electric transmission companies, there have been around 40 cases decided by the FERC over the last five years, and prior to that around 8 decisions per annum was typical.

309. Recovering costs of new infrastructure would also require a rate case to be filed. FERC also has the authority to initiate a review to determine whether a rate of return is "just and reasonable". In some cases, a settlement or agreement with the customers is achieved, precluding the need for FERC to determine a rate case. A settlement is ultimately subject to FERC approval.

Natural gas pipelines

310. The rate of return process for gas pipelines is governed by the Natural Gas Act (NGA), which requires that rates charged for interstate pipeline services be "just and reasonable."[166] The methodology for rate regulation is determined in response to disputes over what rates are just and reasonable. Disputes are heard before FERC judges, with all affected parties offered the opportunity to testify.[167] The FERC's staff also provides testimony, which is generally considered persuasive, but is often criticized by affected parties and may ultimately be rejected by the FERC judge or Commission. Fully litigated cases form precedent methodology (known as "FERC Opinions") that are referenced in future disputes. The FERC is also guided by periodic policy statements; however, the FERC is not required rigidly to adhere to these statements.

311. FERC opinions and policy statements form the guidelines under which the FERC examines future disputes. Beyond the procedural schedule associated with these disputes, there is no schedule for ratemaking determinations. Existing rates may continue until one party challenges the existing rates as unjust and unreasonable.

312. In practice, many pipelines may go many years (ten years or more) without a rate case. Furthermore, most rate cases are ultimately settled rather than litigated all the way through. Thus, final FERC decisions on rate cases are rare (often less than one per year), although typically there will be several such cases filed each year. FERC's preferred rate of return methodology changes relatively infrequently. Prior to the recent Pipeline Policy Statement, the DCF model had been the sole method since the 1980s.[168]

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165 The last major decision by the FERC for a gas pipeline was *El Paso Natural Gas Company* 145 FERC ¶ 61,040, 2015.

166 The FERC's recent pipeline policy statement contains detailed information on the FERC's approach to determining the return on equity for natural gas pipelines. *See* Inquiry Regarding the Commission's Policy for Determining Return on Equity, 171 FERC ¶ 61,155 (2020).

167 This takes the form of prepared written testimony, which is akin to a report or expert opinion, as well as oral testimony in a formal hearing.

168 FERC Proposed Policy Statement, Docket No. PL07-2-000, July 2007, p. 2.

313. Decisions by the FERC can be challenged in the courts. Indeed, the FERC pays careful attention to various judicial decisions (including decisions by the Supreme Court and the D.C. Circuit) when it issues opinions or policy statements. In particular, the FERC will often reference judicial decisions when making adjustments to its methodology for determining the cost of equity.

Electricity transmission

314. Similar to natural gas pipelines, there is no predetermined frequency with which a transmission entity has its rates (including cost of capital) reset. The transmission entity, interveners (customers) or the FERC can request a proceeding to determine new rates. In the case, interveners or the FERC request a proceeding to set a new return on equity, interest rate, and capital structure, they invoke Section 205 and 206 of the Federal Power Act, which requires the rates, terms and conditions are just and reasonable and not unduly discriminatory or preferential.[169] In cases filed by interveners or the utility, the FERC determines whether there is evidence that rates have become unjust or unreasonable.

315. An electric transmission case can be settled at any time during the proceeding, but such settlements need to be approved by the commissioners. In practice, settlements are more common than litigated cases.

316. One unique aspect of electric transmission matters is that they can pertain to either a single utility (a so-called single filer) or regional transmission organization (RTO and so-called group filer). While most aspects of a rate case and the ROE determination is the same, there are some differences with respect to the final determination of the authorised ROE.

317. The determination of the authorised return is guided by the FERC's policy statements and orders. In the case of electric transmission, there has been a series of orders pertaining to regional transmission organizations over the past few years as well as cases appealed to the courts. As a result two key orders emerged: the New England Rehearing Order and Order 569.[170] We focus on these orders and especially the most recent Order 569/569-A, which applied to the Midcontinent Independent System Operator (MISO).

318. In addition to the orders pertaining to the determination of the authorised return, the FERC has issued several policy statements and orders regarding transmission rate making that intent to incentivize transmission investments that the FERC seek to promote. Specifically, the FERC in 2006 implemented the Energy Policy Act of 2005 in Order 679, which provided transmission entities incentives in the form of ROE adders that were granted for joining a regional transmission organization

[169] https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-0ad.txt

[170] Order Directing Briefs re. New England Transmission Owners, October 16, 2018; 165 FERC ¶ 61,030 and FERC Order 569-A re. MISO, May 21, 2020; 171 FERC ¶ 61, 154.

(adding 50 bps to ROE) and adding up 150 to for projects that faced unique technological or other risks.[171] However, on March 19, 2020, the FERC issued a proposed new rule for incentives that could enhance the ROE through incentives as follows:

a. Increase the incentives for joining a regional transmission organization to 100 bps

b. Allow 50 bps incentive to transmission projects that meet a pre-construction benefit-to-cost ratio in the top 25% of the projects examined in the same period

c. Allow up to 50 bps incentive to transmission projects that demonstrate reliability improvements

d. Provide up to 50 bps incentives for transmission projects that use technologies that enhance reliability, efficiency and capacity as well as improve the operation of new or existing facilities.[172]

2. Rate of return

a. The overall rate of return

319. Typically, FERC electric transmission decisions apply to groups of electric transmission companies (so called "group filers"). In some circumstances the FERC will issue a decision for an individual filer. The methodological approach to the cost of equity is similar—for both group and individual filers the FERC will determine the cost of equity based on a statistical analysis of the cost of equity estimates for a sample group of comparable companies.[173]

320. FERC typically allows the embedded cost of debt, and actual gearing based on book values.[174]

321. The following example is from the recent FERC Order 569-A decision noted above. Order 569-A both (i) established certain revisions to the cost of equity methodology for electric transmission companies, and (ii) determined the cost of equity for MISO's electric transmission companies.[175] Based on the cost of equity estimates,

[171] FERC Order No. 679, "Promoting Transmission Investment through Pricing Reform," July 20, 2006.

[172] FERC Notice of Proposed Rulemaking, Docket No. RM20-10-000, March 19, 2020.

[173] This may include the parent entities of the MISO companies themselves, to the extent that they are publicly listed. For group filers where the risk of the target entities is considered comparable average risk in the sample, the FERC's current policy is to reference the midpoint of the sample estimates, whereas the FERC will reference the median of the sample estimates for individual filers of average risk. We discuss the FERC's approach to determining the appropriate position within the sample in "Adjustments for Risk" below.

[174] There are exceptions to the use of the book values, which is describe below.

[175] Typically, the FERC does not make changes to methodology in individual revenue determinations.

the FERC constructs a so-called Zone of Reasonableness, which eliminates low and high outliers,[176] but otherwise ranges from the lowest to the highest estimate.

Table 11
FERC Methodology, Cost of Equity

Measure		Estimate	Methodology
Zone of Reasonableness			
DCF Model, Minimum	[1]	7.37%	Minimum ROE in the sample, DCF model.
CAPM Model, Minimum	[2]	8.35%	Minimum ROE in the sample, CAPM model.
Risk Premium Model, Minimum	[3]	8.22%	Inputed based on the average range of the DCF and CAPM ROE results.
Lower Bound, Zone of Reason.	[4]	7.98%	Average of minimum results.
DCF Model, Maximum	[5]	11.37%	Maximum ROE in the sample, DCF model.
CAPM Model, Maximum	[6]	12.63%	Maximum ROE in the sample, CAPM model.
Risk Premium Model, Maximum	[7]	12.36%	Inputed based on the average range of the DCF and CAPM ROE results.
Upper Bound, Zone of Reason.	[8]	12.12%	Average of maximum results.
Midpoint, Zone of R. [Allow. ROE]	**[9]**	**10.05%**	**MISO TO's considered of average risk.**
DCF Model, Inputs			
Unadjusted Dividend Yield	[10]	n/a	Average monthly dividend yield over the last 6 months.
Short-term Growth Rate	[11]	n/a	Consensus IBES 3-5 year earnings per share growth estimates.
Adjusted Dividend Yield	[12]		
Projected Long-Term GDP Growth	[13]	4.35%	Long-term projected nominal GDP growth.
Composite Long-Term Growth Rate	[14]	n/a	
DCF Model, ROE	**[15]**	**9.37%**	**Reported figure is midpoint used by the FERC.**
CAPM Model, Inputs			
Risk-free Rate	[16]	2.70%	30-year U.S. Treasury.
Market Risk Premium	[17]	8.60%	One-step DCF model for S&P 500 companies.
Equity Beta	[18]	0.84	Determined for each sample company. Implied beta shown.
Size Adjustment	[19]	0.61%	Premium or discount applied to each sample company based on size.
CAPM Model, ROE	[20]	**10.49%**	**Midpoint of the sample.**

Notes and sources:
[1]: Order 569-A, Appendix 3.
[2]: Order 569-A, Appendix 3.
[3]: Order 569-A, Appendix 3.
[4]: Average of [1]-[3]
[5]: Order 569-A, Appendix 3.
[6]: Order 569-A, Appendix 3.
[7]: Order 569-A, Appendix 3.
[8]: Average of [5]-[7]
[9]: Average of [4] and [8]
[10]: Determined for each sample company. Order 569 pp. 51-52.
[11]: Determined for each sample company. Order 569 para. 98.
[12]: [10]*(1 + 0.5*[11])
[13]: Average of multiple sources. Order 569-A, Appendix 2.
[14]: [11]*80% + [13]*20%. Determined for each sample company. Order 569-A, p.31.
[15]: [12] +[14]. Determined for each sample company.
[16]: Average historical bond yield over a six-month period. Order 569, para. 230.
[17]: For each S&P 500 company, first sum the IBES 3-5 year EPS growth rate and dividend yield ("expected return"). Risk-free rate subtracted from the market capitalization weighted expected return. Elimination of companies with growth rates that are not between 0 and 20%. Order
[18]: FERC does not disclose sample betas. We have calculated the implied beta based on other inputs. Source: Value Line.
[19]: Median from a representative sample. FERC does not disclose the size adjustment for sample companies. Source: Duff & Phelps.
[20]: For each sample company, ROE is: [16] + [17]*[18] + [19]. Sample midpoint shown. Opinion No. 569-A, P 179 and App. 3.

[176] Technically, the FERC eliminates estimates that are 200% above the median and lower than the yield on BBB rated utility debt plus 20% of the estimated MRP.

322. The CAPM-based ROE of 10.49% shown in Table 11 is the midpoint of the range. FERC does not prescribe a blanket equity beta or a size adjustment for the CAPM model. Rather, the FERC calculates the CAPM results at the individual sample company level using company specific equity beta and size adjustments, then references summary statistics from the sample when formulating ROE. Table 11 includes median data for the size adjustment and the implied equity beta.

b. Cost of debt

323. The FERC typically sets the authorised rate of return for debt equal to the embedded coupon rate on the company's actual outstanding debt, rather than the current market cost of debt.

324. In the case of an entity that is developing a new project and hence has no embedded cost of debt, the FERC has in the past relied on the publicly observable yield on debt of the same rating as the proxy group.[177]

c. Cost of equity

325. The methodology for determining ROE is determined through two primary avenues. First, the FERC may issue opinions on methodology in response to disputes over just and reasonable rates. The FERC may also issue policy statements clarifying the most up to date methodology. This may follow a consultation period where the FERC invites interested parties to opine on the most appropriate methodology.

326. For example, on March 21, 2019 the FERC issued a "notice of inquiry" seeking information and stakeholder views regarding whether, and if so how, it should modify its policies concerning the determination of the ROE for interstate pipelines.[178] On May 21, 2020 the FERC issued its policy statement on pipelines ROE.[179] This was the first time the FERC had modified its policy since 2008, when it modified its approach to the formation of an appropriate sample.[180] The response summarized the views put forward by stakeholders and included a determination by the FERC. On the same day, the FERC issued Order 569-A relating to a dispute regarding the ROE for electricity transmission providers.[181] Order 569-A included a determination on ROE for the dispute as well as a determination on the best methodological approach for electricity transmission providers. Order 569-A

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177 See, for example, 149 FERC ¶61,183 "Order Conditionally Accepting Tariff Revisions Subject to Compliance Filing," re. PJM Interconnection, November 28, 2014, para 59-94.

178 *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (2019).

179 *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (2020).

180 *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, Policy Statement, 123 FERC ¶ 61,048 (2008).

181 *Order 569-A*, Order on Rehearing, 171 FERC ¶ 61,154 (2020).

updated certain methodology changes outlined in Order 569, issued in 2019.[182] Both opinions retained various methodology changes detailed in the NETO Briefing Order issued in 2018.[183] The Pipeline Policy Statement referenced Order 569-A, in some cases adopting the same approach as Order 569-A. The FERC provided justification for differences in the methodological approach between Order 569-A and the Pipeline Policy Statement. For example, different approaches are required due to smaller sample sizes for gas pipelines.

327. The methodology referenced in Order 569-A and the gas policy statement continue to represent FERC methodology until they are superseded by new opinions or policy statements. A key goal for the FERC is achieving methodological consistency, particularly given the threat of legal challenge in federal courts.

328. The FERC will adjust ROE for the target entity based on an assessment of relative risk. For example, the FERC may grant "incentive ROE" (adding up to 100 bps to the base ROE) for projects where the applicant has shown the project has substantial regulatory approval risk, construction risk, or relies on a new technology.[184] Additionally, for electric transmission, the FERC relies on credit ratings to assess the business risk of comparable companies and selects only those companies that have a credit rating of plus or minus one notch from the target entity.[185]

329. The FERC requires that the rate of return calculations are performed using the most recently available market data at the time testimony is delivered unless the current market data are unreliable. There is no requirement for the rate of return calculations to align with the timing of regulatory accounting data used in the rate case. For example, the rate of return may be determined as of the February, 29, 2020, even if the most recent regulatory accounts are dated December 31, 2019.

330. The FERC may also ignore market data if conditions in the financial market are considered anomalous. For example, the FERC has chosen to ignore data during the global financial crisis of 2008-2009.[186] In these scenarios, the FERC will examine the cost of capital for the period immediately prior to the anomalous market data.

331. The first step in the process prescribed by the FERC involves the selection of a comparable group of companies. The FERC has historically preferred only US-based companies, however difficulties associated with obtaining a large enough sample size for gas pipelines, have led the FERC to recently consider Canadian companies. Indeed, there is only one remaining US-based "pure play" gas transmission

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182 *Association of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator, Inc.*, 169 FERC ¶ 61,129 (2019)

183 *Coakley Mass. Attorney General v. Bangor Hydro-Elec. Co.*, *order on remand*, 165 FERC ¶ 61,030 (2018).

184 See, for example, FERC Order on Petition for Declaratory Order re. AWC, 135 FERC ¶61,144; May 19, 2011, para 56-66.

185 See, for example, Order in Docket ER08-92-000, 2009.

186 *SFPP, L.P.,* 162 FERC ¶ 61,228 at P 37 (2018) ("Opinion No. 511-C").

company. This can result in controversy over how to construct a reliable sample. Sample selection is less controversial in electric transmission cases, where the FERC focuses on a broad range of US electric utilities (typically 30-40), none of which have a high proportion of assets devoted to transmission. The FERC prescribes multiple models to estimate ROE, each of which are applied to individual companies in the sample.[187] The results are combined to form a "zone of reasonableness". The allowable ROE within the zone of reasonableness is determined by the relative risk of the target entity (or entities) in question. For example, an average risk target entity would be placed at the median of the zone of reasonableness. More commonly, allowable ROE is determined for group filers. For group filers, the FERC will reference the midpoint of the sample (provided that the entities in question are considered of average risk). The zone of reasonableness is less relevant for gas pipelines, as the FERC focuses on median results and is less likely to view a pipeline as anything other than average risk.[188]

332. One of the key areas of dispute between parties has been the formation of an appropriate sample. In particular, sample selection has become controversial for gas pipelines, due to a declining number of publicly listed companies with a high proportion of their activities devoted to gas transmission. Historically, the FERC required all sample companies to be US based with at least 50 percent of either income or assets related to gas transmission.[189] However, in order to maintain a sufficient sample size, the FERC has relaxed this requirement. In the recent 2020 policy statement, the FERC stated that it will relax this requirement until at least five companies fall within the sample, and the sample may include otherwise comparable Canadian companies.[190]

333. The FERC has historically placed significant emphasis on the discounted cash flow (DCF) model. In particular, for gas pipelines, until recently the DCF model has been used almost exclusively to determine ROE. In submissions to the FERC, the Brattle group has argued that it is preferable to reference the ROE results from multiple models, as each model has strengths and weaknesses and each is potentially capable of generating relevant evidence as to returns demanded by investors. In a 2020

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[187] The exception is the risk premium model, which produces a single estimate.

[188] In Transcontinental Gas Pipe Line Corp, the FERC found that "pipelines fall into a broad range of average risk, absent highly unusual circumstances …" (126 FERC ¶ 61,034, para 138-146). However, in Kern River 2009 (126 FERC ¶ 61,034, para 138-146), the FERC found that given a small proxy group consisting in part of companies with gas distribution operations, the FERC added 50 basis points to the ROE to account for the higher risk of Kern River than the sample.

[189] *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, Policy Statement, 123 FERC ¶ 61,048 (2008) p. 4.

[190] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (2020), p. 39.

policy statement, the FERC prescribed an ROE based on an equal weighting of the DCF and the Capital Asset Pricing model (CAPM) for gas pipelines.[191]

334. The FERC has prescribed a broader range of models for evaluating the ROE of electric transmission companies. A 2018 opinion by the FERC prescribed an equally weighted ROE derived from four models (i) DCF; (ii) CAPM; (iii) Risk Premium, and (iv) Expected Earnings.[192] Following ongoing debate, a recent 2020 opinion (Order 569-A) eliminated the Expected Earnings model.[193] Table 12 summarizes the key inputs and ROE output from the DCF model from the recent Order 569-A. The FERC does not disclose sample data for the CAPM model.[194] Refer to Table 11 for a summary of the key inputs to the CAPM model.

Table 12
DCF Model Inputs and ROE Output, Order 569 (MISO companies)

Measure	Sample Range
DCF Model	
Unadjusted Dividend Yield	2.84% - 5.47%
Short-term Growth Rate	-0.92% - 9.35%
Adjusted Dividend Yield	2.84% - 5.48%
Projected Long-Term GDP Growth	4.35%
Composite Long-Term Growth Rate	0.13% - 8.35%
ROE	**3.92% - 11.37%**

335. Following is a summary of FERC's approach for each ROE model.

DCF Model

336. The FERC's DCF model is a modification of the standard, constant-growth DCF model, into a two-step DCF model. In the first step of the model, the short-term dividend growth rate is multiplied by one half of the company's short-term (3-5-year) analyst growth rate estimates.[195] In the second step, the longer-term growth rate is a weighted average of the short-term growth rate (2/3rd and 4/5th weighting

[191] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (2020), p. 2.

[192] *Coakley Mass. Attorney General v. Bangor Hydro-Elec. Co.*, *order on remand*, 165 FERC ¶ 61,030 (2018) ("NETO Briefing Order").

[193] *Order 569-A*, Order on Rehearing, 171 FERC ¶ 61,154 (2020), p. 26.

[194] The risk premium model relies upon a regression of data relating to past decisions by the FERC.

[195] The Commission has shown a preference for referencing the consensus 3-5 year earnings per share growth estimates collected by Thomson Reuters (commonly referred to as "IBES" estimates).

for gas and electric respectively), and an estimate of long-term GDP growth (1/3rd and 1/5th weighting for gas and electric respectively).[196]

337. The DCF formula is as follows:

$$k = \frac{D_0 \times \left(1 + \frac{1}{2} g_1\right)}{P} + g_2$$

338. Where D_0/P is the dividend yield, k is the return on equity, g_1 is the short-term analyst growth rate and g_2 is the composite long-term growth rate.[197]

339. In applying a two-step model with a weighted average long term growth, the FERC has recognized that a company cannot continue to grow at rates that exceed GDP in the longer term. Although companies can experience very high rates of growth from time to time (i.e., greater than the growth of the economy as a whole), these high rates cannot generally be expected to last indefinitely. Conversely, very low rates of growth in the near term can generally be expected to improve over time.

340. The FERC has established a very specific procedure for calculating the dividend yield to use in the DCF formula. Specifically, the "current" dividend yield is to be computed using the prior six months of dividend and price data. One first records the highest and lowest trading price during the month for each of the prior six months, and takes the average. The current dividend for each quarter is annualized (i.e., multiplied by 4) and then divided by each of these monthly average prices to produce six monthly dividend yields. Averaging these six dividend yields produces an estimated dividend yield for each company as of today.

341. To adjust for the timing in how dividends are paid and the fact that they are paid quarterly, the FERC multiplies the short-term growth by 0.5. According to the FERC, the rationale is "to account for the fact that dividends are paid on a quarterly basis. Multiplying the dividend yield by (1+.5g) increases the dividend yield by one half of the growth rate and produces what the Commission refers to as the "adjusted dividend yield."[198] Brattle has provided testimony to the FERC that disagrees with the 0.5 multiplier for the initial growth rate as a matter of economic principle because it violates the basic assumptions of the DCF model. The DCF model is derived under the assumption that dividends grow at the full growth rate for the period. However, recent opinions and policy statements have made no adjustment to this assumption.

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196 The FERC eliminates from the sample any companies with negative short-term growth rates (We discuss sample selection issues further below). The FERC's rationale for different growth rates for gas and electric is the different growth outlook for these industries.

197 *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (2020), pp. 3-4. For electric transmission companies, the FERC's latest policy regarding the split between short and long term growth rates is described in *Order 569-A*, Order on Rehearing, 171 FERC ¶ 61,154 (2020), p. 31.

198 *Order 569*, Order on Briefs, Rehearing, and Initial Decision, 169 FERC ¶ 61,129 (2019), p. 88.

CAPM Model

342. The FERC has adopted a standard version of the CAPM model, with some noteworthy choices for the CAPM inputs. For the equity beta, the FERC references data from Value Line.[199] Value Line betas are estimated using 5 years of weekly return data (i.e., 260 weeks) using the NYSE as the market return, and are "adjusted" following Blume (1971). Adjusted beta is calculated as 0.35 + 0.67 * raw beta.[200] The adjustment moves all betas/returns closer to the market return (i.e., beta of 1).

343. The FERC has also prescribed a size-based modification to the CAPM based on estimates provided by Duff & Phelps.[201] The size adjustment is based upon empirical evidence from academic studies documenting a difference between a company's theoretical return as estimated by the CAPM and its realized return. The difference is a function of the size of each comparable company, where size is measured by its market capitalization. The size adjustment applied to the CAPM estimates is reported by Duff & Phelps for the market as a whole by size decile. The smallest decile of companies requires the largest addition to the expected return estimated solely from beta, while stocks in the largest decile have shown an empirical tendency to return less than the rate of return predicted by beta; hence, companies with very large market capitalizations receive a downward adjustment. The calculated return on equity for each company in the proxy group is adjusted in this way. For 2019, the size based adjustments published by Duff & Phelps ranged from -0.28% to 4.99%.[202] For the companies in the Order 569-A sample, we estimate that the median size-based adjustment was 0.61%.

344. The market risk premium (MRP) is calculated by implementing a single stage DCF model for the dividend paying companies in the S&P 500 index. The expected market return is calculating as the market-value weighted-average of the individual company DCF estimates (dividend yield plus expected growth).[203] To derive the MRP, the 6-month average yield on 30-year Treasury bonds is subtracted from the expected market return.[204] The averaging period should correspond as closely as possible to the six-month financial study period used to produce the DCF study in the applicable proceeding.[205]

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199 *Order 569-A*, Order on Rehearing, 171 FERC ¶ 61,154 (2020), p. 39.

200 This formula is used by the data provider Value Line, which FERC prefers for beta estimates. The formula is derived from the standard Blume adjustment of 0.33 + 0.67*raw beta, however it does not follow the standard 1/3 and 2/3 weighting.

201 *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (2020), p. 25.

202 The Duff & Phelps size-based adjustments are available using the Cost of Capital Navigator.

203 The FERC excludes growth rates less than 0% or greater than 20%. *Id.*, p. 40.

204 *Id.*, p. 15.

205 *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (2020), p. 26.

345. For the purposes of determining the risk-free rate, the FERC prescribes the 30-year US Treasury average historical bond yield over a six-month period.

Risk Premium Model

346. The Risk Premium model analyses past ROE decisions to determine a current ROE benchmark. The FERC has recognized that there is a statistically significant relationship between historical movements in interest rates and equity risk premiums (defined as the authorised return on equity for electric transmission utilities over and above utility bond rates). When interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. In order to calculate the equity risk premium, the FERC examines all electric transmission determinations after the Energy Policy Act of 2005.

347. The FERC method is implemented using a standard linear regression. Actual equity risk premiums for individual rate cases, including settlements[206] from 2006 onwards are regressed on a Baa Moody's-rated index of utility bond yields.[207] The FERC then calculates the implied current equity risk premium, and adds this value to the current projected utility bond yield.[208]

Adjustments for Risk

348. The results of each model are combined into a "zone of reasonableness". The top estimate from each model is averaged to form an upper bound, and the bottom estimate for each model is averaged to form a lower bound. The range from the lower bound to the upper bound represents the zone of reasonableness. If the target entity (or group of entities, in the case of an ISO) is considered of average risk, the ROE is set at the central tendency of the zone of reasonableness. For rate cases involving group filers, ROE is set at the midpoint of the zone of reasonableness. For rate cases involving individual target entities, the FERC references the median. If a company has a risk profile that is significantly different to the average risk profile of the sample, the return may be set at a different percentile position amongst the range of ROEs.[209]

349. For gas pipelines, the FERC's established policy is to use the median ROE of the sample based on the assumption that "gas pipelines generally fall into a broad range

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206 Certain rate cases are excluded.

207 Actual equity risk premiums are calculated based on the allowed ROE for electric utilities, less the prevailing yield on public utility bonds for the current test period. The data on utility bond yields is publicly available.

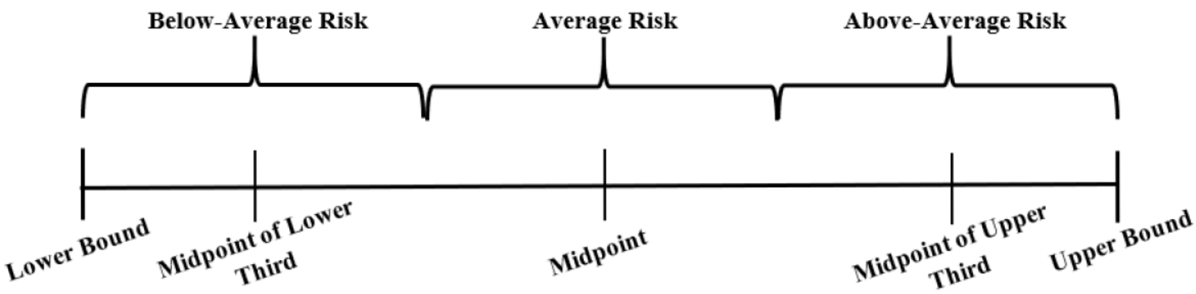
208 Near-term projections are taken from leading macroeconomic forecasters and government agencies. For example, IHS Global Insight, Moody's Investors and the Energy Information Administration.

209 *Id.*, p. 80.

of average risk."[210] Absent "highly unusual circumstances that indicate anomalously high or low risk as compared to other pipelines," the FERC prescribes the median ROE.[211] Although the FERC has indicated that it will consider specific risk factors on a case-by-case basis, it has not articulated a specific set of criteria for evaluating the relative risk of a regulated entity. For most pipelines, the FERC will take an average of the median result from the DCF and CAPM models.[212]

350. In the recent Order 569-A, the FERC updated its method for adjusting risk of an electric transmission company.[213] The following figure illustrates how the FERC adjusts for risk when determining allowable ROE for a group of electric transmission companies.

Figure 7
The zone of reasonableness



351. As shown in Figure 7, when the FERC considers the target entities to be of average risk, it prescribes the midpoint of the zone of reasonableness. The lower end of the zone of reasonableness is the average of the lowest results from each of the models.[214] The high end of the zone of reasonableness is the average maximum result from each of the models. If the target entities have *above* average risk, they are prescribed an ROE at the midpoint of the upper third of the sample. If the target entities have *below* average risk, they are prescribed an ROE at the midpoint of the

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210 *Kern River Gas Transmission Company*, 117 FERC ¶ 61,077 at P 170 (2006).

211 *Id.*

212 Very rarely the FERC will deviate from the median. For example, in Kern River, the FERC added 50 basis points to the median as the list of comparable companies was small and included companies with a relatively low proportion of pipeline business and substantial distribution operations. *See* Kern River Gas Transmission Co., 129 FERC ¶ 61,240 (2009) at P 2. Similarly, in 2013, the Commission recognized "highly unusual circumstances" where Portland Natural Gas Transmission had higher risk than the comparable companies in the sample and should be placed at the top of the ROE range produced by the sample group in that proceeding. *See* Portland Natural Gas Transmission System, Opinion No. 524, 142 FERC ¶ 2 61,197 (2013), order on reh'g, Opinion No. 524-A, 150 FERC ¶ 61,107 (2015).

213 *Order 569-A*, Order on Rehearing, 171 FERC ¶ 61,154 (2020), p. 80.

214 As the Risk Premium model produces a single ROE estimate, the range for this model is imputed based on the range from the other models.

lower third of the sample. By focusing on the midpoint, the results are heavily influenced by the extremes in the sample. For individual companies the FERC follows a similar method, instead focusing on the median of the relevant third of the sample.

352. In order to understand risk of the target entity (or entities), the FERC has typically relied heavily on credit ratings.[215] In the recent Northern Natural Gas rate case, the FERC's Staff Witness relied on business risk profile ratings published by credit rating agencies. In addition to business risk, the FERC's Staff Witness also examined financial risk (i.e., relative gearing). Affected parties will often employ specialized experts to opine on business risk.[216]

d. Gearing

353. Provided that gearing is not excessively low,[217] the FERC will apply the WACC to the target entity's actual gearing. The FERC does not have a stated policy for determining whether gearing is excessive, however the FERC appears to be content with the target entity's actual gearing when actual gearing is within the range of gearing levels for comparable companies.[218] If gearing appears excessively low (e.g., much lower than that of the comparators' gearing because, for example, the debt is held higher up in the corporate structure), FERC may use a hypothetical gearing level, or alternatively, the gearing of a corporate parent entity. For gas pipelines, the typical structure comprises around 40% debt.[219] For electric transmission the commonly used gearing is 40-50% debt.

e. Treatment of tax and inflation

354. As the market data referenced by the FERC on the cost of equity reflects required returns after corporate taxes, the authorised ROE is an after-corporate tax rate of

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215 The FERC does not have a stated policy for determining business risk.

216 For example, the expert examining the business risk of a gas pipeline may consider such things as the pipeline's exposure to the market value of capacity, competition from bypass arrangements, operating risks from required capital expenditures, or demand for storage services. For transmission projects, experts may similarly examine the exposure to demand changes, competition, and supply issues.

217 The FERC has no stated policy on a cutoff level, but as noted below consider the gearing of the comparators to assess reasonableness.

218 See, for example, FERC Opinion 546, "Seaway Crude Pipeline Company LLC," February 1, 2016, para 172.

219 While we are not aware of examples of FERC electric transmission cases, where the FERC has found the equity ratio to be excessive, the FERC used a gearing of 40 percent in several pre-approvals for transmission projects. See, for example, FERC, "Order on Petition for Declaratory Order," 135 FERC ¶61,144 re. Atlantic Grid Operations, May 19, 2011, para 21 and 121.

return. FERC's revenue determination accounts for taxes by calculating a tax allowance equivalent to grossing up the rate of return at the statutory tax rate.[220]

355. There are no adjustments made to the statutory rate. For example, if accelerated depreciation is available, so that tax depreciation will be larger than financial (or regulatory) depreciation, this is not taken into account in calculating the income tax allowance. However, the value of the authorised rate base *does* reflect income tax timing differences. Thus, for example, accelerated depreciation in prior years may result in a build-up of the accumulated deferred income tax liability on the entity's financial reporting accounts, reducing net assets. Similarly, accumulated deferred income tax will appear as a liability on the entity's regulatory accounts, and will reduce the amount of rate base that is funded by equity investors.[221] Specifically, the rate base is calculated as follows:[222]

$$Rate\ Base = Net\ Assets + Working\ Capital - Accumulated\ Deferred\ Income\ Tax$$

356. Tax rules are such that being able to access accelerated depreciation is contingent on the regulator providing the full amount of tax in current revenues, which FERC does. FERC requires the utility to track, in its regulatory (and financial) accounts, the accelerated tax depreciation which gives rise to a future income tax liability (accumulated deferred income tax), which for ratemaking purposes is treated as a contribution from customers to the financing of rate base with a zero cost.

357. The FERC measures rate base using the original cost method, wherein the rate base is equal to the original cost of assets, less accumulated depreciation. The absence of any inflationary adjustment leads to an erosion in the real rate of return on assets. Relative to rate base measures that seek to reflect the current value of the rate base, original cost measures have a "front end load" and a "tail end shortfall". When new assets have a much larger cost than the book value of the assets that are replaced, there can be a large increase in rates, as the rate of return is applied to a larger rate base.

f. Imputation tax credits

358. Not applicable

g. Other factors

359. Not applicable

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220 This excludes Master Limited Partnerships and municipally-owned utilities, which are not subject to corporate income tax.

221 The deferred income tax liability is sometimes referred to as zero cost capital.

222 There may be other smaller adjustments to rate base.

D. The US Surface Transportation Board

360. The Surface Transportation Board (STB) primarily regulates freight railroads in the US.[223] Among the STB's regulatory responsibilities is the annual determination of the railroad industry's cost of capital.

1. The regulatory framework

a. Objective

361. The cost of capital is used (1) to undertake an annual evaluation of the railroads' revenue adequacy and (2) in disputed regulatory proceedings involving the prescription of maximum reasonable rate levels in cases, where customers lack alternative, in proposed abandonment of rail lines, and the setting of compensation for use of another carrier's lines.[224] The cost of capital is not used to determine the freight railroads' rate absent a scenario listed in (2) above. However, the STB has been considering using the finding of revenue adequacy to cap rates.[225] As defined by the STB, a railroad's revenue is adequate if it has achieved a rate of return on its invested capital that is at least equal to the STB's estimated cost of capital for comparable risk investments. This test is intended to ensure railroads' financial integrity (meaning its return on investment matches the estimated cost of capital over a longer horizon). For context, the STB has in the past been concerned about the viability of freight railroads. The key parties involved include the major railroad companies and the shipping companies that ship on the railroads. While some shippers own rail cars, the locomotives and many rail cars are owned by the Class 1 railroads, which are subject to STB oversight.[226] The cost of capital has an impact on how much some shipping companies pay to use the railway assets and in particular how much customers with no alternatives pay. A key group of shippers are coal shippers.

b. Timing and sequencing

362. The STB determines the railroads' cost of capital annually—usually well into the subsequent year. Typically the cost of capital for a year is determined by the middle of the next year, as it is used to check revenue adequacy and to resolve issues ex post.

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223 The STB also has jurisdiction in some pipeline, trucking, and ocean shipping matters. *See* https://prod.stb.gov/about-stb/.

224 STB, *Decision Railroad Cost of Capital - 2013*, Docket No. EP 558 (Sub - No. 17), July 31, 2014.

225 See, for example, AAR, "Revenue Adequacy: A Calculation to Inform Regulators of Railroads' Financial Health, Not to Cap Rail Rates." Available at https://www.aar.org/wp-content/uploads/2019/11/AAR-Revenue-Adequacy-Fact-Sheet.pdf

226 Currently four railroad holding companies meet these criteria: CSX Corporation (CSX); Kansas City Southern (KCS); Norfolk Southern Corporation (NSC); and Union Pacific Corporation (UPC).

363. The rules under which the cost of capital are determined by infrequent updates to STB Decisions. Currently, the STB calculates the cost of capital for a "composite railroad" based on criteria developed in Railroad Cost of Capital—1984, 1 I.C.C.2d 989 (1985), and modified in Revisions to the Cost-of-Capital Composite Railroad Criteria, EP 664 (Sub-No. 3) (Oct. 25, 2017).[227] Any significant changes to methodology are generally preceded by a Notice of Proposed Rulemaking ("NOPR") and a public consultation process, including public hearings and multiple rounds of written testimony. For example, the STB has recently proposed changes to one of its two relied upon methods—its Multi-Stage Discounted Cash Flow (MSDCF) model.

2. Rate of return

a. The overall rate of return

364. The cost of capital is a vanilla nominal WACC with a gearing based on the market value of the railroads' capital structure.

365. The cost of capital is determined annually using a formulaic approach based on the prevailing methodology. The STB makes a determination on a single cost of capital, which applies to all railroads, regardless of their size. The data for the cost of capital calculations is based on the major publicly listed railroads. Until 2010, all five major railroads were also publicly listed. However, in 2010 Berkshire Hathaway purchased BNSF. As such, the data for the cost of capital is now based on four major railroads. Table 13 shows the 2018 cost of capital decision issued by the STB on September 30, 2019. The cost of capital decision is based on portfolio data for the four major publicly listed railroad companies. The same cost of capital is applicable industry-wide to all relevant regulated railroad activities.[228]

[227] The composite railroad includes those Class I carriers that: (1) are listed on either the New York Stock Exchange (NYSE) or Nasdaq Stock Market (NASDAQ); (2) paid dividends throughout the year; (3) had rail assets greater than 50% of their total assets; and (4) had a debt rating of at least BBB (Standard & Poor's) and Baa (Moody's). *See* Surface Transportation Board Decision, Docket No. EP 558 (Sub-No. 22), Railroad Cost of Capital 2018, p. 3.

[228] Surface Transportation Board Decision, Docket No. EP 558 (Sub-No. 22), Railroad Cost of Capital 2018 (decided September 30, 2019). The aim of the regulation is to produce reasonable maximum rates for situations where there is no competitive alternative.

Table 13
STB Methodology, WACC

Measure		Estimate	Methodology
Cost of Debt (pre-tax)	[1]	4.16%	Market-capitalization weighted average of all bonds across the industry.
Risk-free Rate	[2]	3.02%	Average 20-year U.S. Treasury bond rate in 2018.
Market Risk Premium	[3]	6.91%	Market capitalization decile-based.
Equity Beta	[4]	1.11	Railroad portfolio beta.
CAPM, Cost of Equity	[5]	10.70%	
MSDCF, Cost of Equity	[6]	17.01%	Implied growth rate based on railroad projected cash flows and market capitalizations.
Average Cost of Equity	[7]	13.86%	
Weighting, Debt	[8]	16.92%	Market-weighted industry average.
Weighting, Equity	[9]	83.08%	Market-weighted industry average.
WACC	**[10]**	**12.22%**	

Notes and sources:
Surface Transportation Board Decision, Docket No. EP 558 (Sub-No. 22), Railroad Cost of Capital 2018 ("Decision").
Presented is the 2018 determination applicable to all relevant regulated railroad activities.
[1]: Bloomberg; 10-k reports. Page 7 of the Decision.
[2]: Federal Reserve Board. Page 7 of the Decision.
[3]: Duff & Phelps Cost of Capital Navigator. Page 8 of the Decision.
[4]: Yahoo Finance. Page 8 of the Decision.
[5]: [2] + ([3]*[4])
[6]: MSDCF model. Page 11 of the Decision.
[7]: ([5]+[6])/2
[8][9]: Page 12 of the Decision.
[10]: ([1]*[8]) + ([7]*[9])

b. Cost of debt

366. The STB uses the market yield to maturity on outstanding railroad bonds to determine the cost of debt for bonds. These figures are averaged over the year for which the cost is being determined. The STB also calculates the market yield on other outstanding debt.[229] The STB uses market value for traded instruments and book values otherwise to calculate an industry weighted average cost of debt.

367. The cost of preferred equity is a minor component of the railroads' capital structure. The cost of preferred equity is determined as the market yield on publicly traded preferred equity railroad instruments.

[229] For example, other debt instruments include: (1) bonds, notes, and debentures (bonds); (2) equipment trust certificates (ETCs); and (3) conditional sales agreements (CSAs). The yields of these debt instruments are weighted based on their market values.

c. Cost of equity

368. When determining the cost of equity, the STB currently averages the results from the CAPM model and the Morningstar-Ibbotson Multi-Stage Discounted Cash Flow (MSDCF) model. In 2019, the STB has proposed the addition of an amended "Step" MSDCF model. Under the proposal, the Step MSDCF model would be weighted 25%, the standard MSDCF model 25%, and the CAPM 50%. Various interested parties made submissions based on the NOPR. On June 23, 2020 the STB elected not to proceed with the Step MSDCF model.[230]

369. In 2018, the cost of capital produced by the MSDCF model was high relative to earlier years. At the end of 2018 (when ROE was calculated), the market capitalizations of the major railroads dropped significantly. As the MSDCF model calculates an implied rate of return, all else equal, a drop in market capitalization will lead to an increase in the implied rate of return. However, a decline in market capitalization would normally be associated with a decline in growth rates. In this case, many of the growth rates were significantly lagged, as analysts typically only update their forecasts after earnings results are released in late January. To mitigate this issue, Brattle has recommended to the STB that it moves from end of December to end of January data. By moving to January data we demonstrate that the lag between the test date and analyst earnings growth estimates is substantially reduced. While the STB followed Brattle recommendations in other respects (electing not to proceed with the version of the Step MSDCF proposed and agreeing that the 2018 data was anomalous), it elected to continue using December data.[231] It was apparent from the proceedings that issues with underlying data represent a weakness with the MSDCF model. The STB has recognised that each model has strengths and weaknesses, motivating the need to rely on multiple models.

The CAPM Model

370. The market risk premium is calculated as the realized S&P 500 index stock market return minus the income return on 20-year US Treasury bonds using the Morningstar-Ibbotson approach and the period 1926 through the current year.[232] The risk-free rate is the average yield on 20-year US Treasury bonds during the year for which the cost of equity is being estimated. Finally, the STB calculates a railroad industry beta using a portfolio approach, where the entities examined comprise the major railroads.[233]

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[230] Surface Transportation Board Decision, Docket No. EP 664 (Sub-No. 4), decided June 23, 2020.

[231] *Id.*

[232] This data was originally compiled in the Morningstar-Ibbotson Classic yearbook, but has since been taken over by Duff & Phelps.

[233] The STB uses a market cap weighted portfolio of all publicly traded Class 1 railroads for the estimation. The following are classified as Class 1 railroads Burlington Northern, CSX, Kansas City Southern, Norfolk Southern and Union Pacific. However, Burlington Northern is not publicly

371. The weight assigned to each railroad uses the railroad company's relative market value of equity. Specifically, the STB calculates the weekly stock market value of equity for each railroad over the year and then averages these figures to determine the weight to assign to each railroad company in the beta calculation. The equity beta is then calculated using 5 years of weekly data for the portfolio.[234]

372. The STB uses the railroads' aggregate market value capital structure to determine gearing, which from 2015 through 2018 ranged from 16.92 (2018) to 20.75 percent (2016).[235] The gearing is lower than that of other regulated industries but reflects the STB's use of the market value weighted capital structure of the railroad industry, which combined with the majority of the railroads relying heavily on equity results in a low gearing. Railroads' revenue is largely linked to the economy and therefore very volatile, which has resulted in the majority of freight railroads have an equity-heavy balance sheet and the solid economy in recent years (up until COVID-19 hit) has resulted in the market value of equity increasing substantially for an even higher equity percentage.

The MSDCF Model

373. Under the Board's established MSDCF model, the cost of equity is the discount rate that equates a firm's market value to the present value of the expected stream of free cash flows that is available for distribution to equity investors. According to the STB: "These cash flows are not presumed to be paid out to investors; instead, it is assumed that investors will ultimately benefit from these cash flows through higher regular dividends, special dividends, stock buybacks, or stock price appreciation."[236] The multi-stage aspect of the model recognizes that growth rates will change over time.

374. The model includes three stages. In both Stage 1 and Stage 2, representing years 1-5 and years 6-10 respectively, free cash flow builds from the base level of "initial cash flow." In order to calculate initial cash flow, the model adjusts income before extraordinary items (IBEI) by deducting capital expenditures (CapEx) in excess of depreciation (D) and adding deferred taxes (DIT). Thus, the cash flow used in the model is a measure of free cash flow available to equity holders.

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traded so only the remaining four ae used. See, for example, STB Decision in Docket No. EP 558 (Sub-No. 22), September 30, 2019, p. 4.

234 See, for example, STB, *Decision Railroad Cost of Capital - 2013*, Docket No. EP 558 (Sub-No. 17), July 31 , 2014, p. 8. As the equity beta is calculated using the portfolio, there is no need to de-lever and re-lever beta for individual railroad companies.

235 Surface Transportation Board Decision, Docket No. EP 558 (Sub-No. 22), September 30, 2019, p. 12 and Surface Transportation Board Decision, Docket No. EP 558 (Sub No. 20), August 4, 2017, p. 13.

236 Surface Transportation Board Decision, Docket No. EP 558 (Sub-No. 22), Railroad Cost of Capital 2018, pp. 8-9.

375. In the first stage of the current MSDCF model, initial cash flow grows in line with median projected growth rates in earnings per share (EPS) provided by railroad industry analysts.[237] Linking cash flows with projected EPS growth rates aligns the model with expected cash flow outcomes. All else being equal, it is logical to expect railroads with relatively high (low) capital expenditure will experience relatively high (low) growth in future cash flow.[238]

376. In the second stage of the current MSDCF model, the assumed growth rate is the simple average of all of the qualifying railroads' median three- to five-year growth rate estimates from Stage 1.[239]

377. In Stage 3, which begins in year 11 and continues into perpetuity, each firm's growth rate is the projected long-run nominal growth rate of the aggregate US economy.[240] In Stage 3, cash flow equals IBEI (i.e., D + DIT − Capex = 0). The rationale for this assumption is that in steady-state the perpetual capital expenditures will consist solely of maintenance capital (no growth capital), so that capital expenditures and depreciation are equal. Further, because deferred taxes are linked to capital expenditures,[241] this amount is expected to disappear as capital expenditures approach maintenance levels in the long-term steady-state equilibrium.[242] Therefore, the adjustment to IBEI (i.e., D + DIT − Capex) will approach zero in the long term.

378. Historical cash flow data is derived from 10-K annual report filings with the SEC. To calculate initial cash flow, the STB calculates the average cash-flow-to-sales ratio for each major railroad for prior 5 years.[243] To obtain the current average cash flow (i.e. for the year that the rate of return will apply to), the cash-flow-to-sales ratio is

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237 The STB relies on consensus earnings per share (EPS) growth estimates provided by Thomson Reuters/IBES to calculate projected cash flows.

238 In recent times, the large US railroads have tended to have high levels of capital expenditure relative to depreciation.

239 The focus of the recently proposed "step" MSDCF model is a way to smooth the transition from Stage 2 to Stage 3.

240 This long-run nominal growth rate is estimated by using the historical growth in real Gross Domestic Product (GDP) plus the long-run expected inflation rate.

241 For capital-intensive industries such as the railroad industry, a large proportion of the deferred income tax is due to differences in the depreciation schedule for tax versus for Generally Accepted Accounting Principles ("GAAP") purposes.

242 Thus, the cash and accrual tax amounts are assumed to be the same.

243 Surface Transportation Board Decision, Docket No. EP 558 (Sub-No. 22), Railroad Cost of Capital 2018, p. 9.

multiplied by the sales revenue from the test year.[244] The average cash flow figure is then used as the starting point of the MSDCF model.

d. Gearing

379. Capital structure is based on a market value weighted industry average. The STB assesses common equity, preferred equity, and debt. The latter includes bonds, notes, debentures, equipment trust certificates, and conditional sales agreements and is thus a bit broader than long-term debt.[245]

e. Treatment of tax and inflation

380. Taxes are normalized (see the discussion above in the FERC section at paragraph 295) and there is a separate tax building block in the determination of the revenue requirement. All determinations are nominal and there is no consideration of inflation (except as an input to the MSDCF model.

f. Imputation tax credits

381. Not applicable

g. Other factors

382. Not applicable

E. The Italian regulatory ARERA

1. The regulatory framework

383. The Italian Regulatory Authority for Energy, Networks and the Environment (ARERA) carries out regulation and control activities for energy infrastructures in Italy. Regulated energy sectors include transmission and distribution of electricity, and transmission, distribution, metering, storage and regasification of natural gas. ARERA also regulates the water and waste industries. Snam and Terna, the main gas and electricity TSOs, are listed companies with indirect partial government ownership. Their largest individual shareholder, with around 30% of share capital, is CDP Reti, a subsidiary of Cassa Depositi e Prestiti, a financial institution controlled by the Italian Ministry of Economy and Finance. There are about 130 electricity DSOs and 207 gas DSOs operating in Italian regions and provinces, organized with a wide range of legal forms, from listed companies, to privately-held companies, to publicly-owned entities.[246]

[244] The test year is the year that data is drawn from. For example, on September 30, 2019, the STB issued an updated final decision relating to the cost of capital for 2018 (the test year) using 2018 data. The 2018 decision can be used to assess any rates charged in 2018.

[245] STB, *Decision Railroad Cost of Capital - 2013*, Docket No. EP 558 (Sub-No . 17), July 31 , 2014.

[246] ARERA, *Relazione Annuale 2019 – Stato dei Servizi, Volume 1*, pp. 88-91, 202-205.

a. Objective

384. Established with Law no. 481 of 1995, ARERA is an independent authority that works to ensure the promotion of competition and efficiency in public utility services and to protect the interests of users and consumers. ARERA performs these functions by harmonizing the economic and financial objectives of the regulated companies with the general objectives of environmental protection and efficient use of resources. ARERA also carries out consultative and reporting activities to the Government and Parliament in matters within its competence, also for the purpose of defining, transposing and implementing Community legislation.[247]

385. ARERA applies sector-specific methodologies for the determination of authorised revenues and tariffs, although the methodology for the rate of return component is common across all the sectors. In the energy sector, ARERA determines authorised revenues based on a regulatory asset base that is indexed to inflation. Authorised revenues are set based on a "building blocks" approach, with depreciation, operating costs, an authorised return on the capital employed as components of the authorised revenue. ARERA uses a pre-tax WACC, so there is no tax building block.

b. Timing and sequencing

386. ARERA generally applies regulatory tariff periods of six years.

387. ARERA has recently harmonised the methodology to determine the authorised rate of return. More specifically, with Deliberation 583/2015/R/COM of 2 December 2015, ARERA introduced a new, common methodology to estimate and update the WACC for all the sectors it regulates.[248] The decision, also referred to as "TIWACC", established a regulatory period for the WACC of six years, divided into two sub-periods of three years each, with only some of the WACC parameters (namely inflation, risk free rate and market risk premium) to be updated at each sub-period. The WACC regulatory period currently does not necessarily coincide with the regulatory periods for the determination of tariffs, although ARERA may gradually align the two for all sectors. It is currently not clear whether gearing will be updated in the sector tariff review or in the WACC (sub-period) review.

388. At the end of every regulatory WACC period or sub-period, ARERA publishes new decisions setting the updated values of the relevant WACC parameters for the regulated sectors. The TIWACC decision is then updated to reflect the new decisions and parameter values. The first WACC regulatory period, 2016-2021, is

[247] Additional details on ARERA's legal framework and functions are provided in its website, available at the link: https://www.arera.it/it/che_cosa/presentazione.htm

[248] ARERA, Deliberation 583/2015/R/COM, Annex A (TIWACC). The updated version is available at the link: https://www.arera.it/allegati/docs/15/583-15tiwacc.pdf

still ongoing, and ARERA has recently updated the TIWACC by re-setting inflation, risk free rate and market risk premium for the sub-period 2019-2021.[249]

389. Once the new WACC parameters have been determined, they are reflected in tariffs in the following year (i.e., without waiting for the next tariff determination).

390. The most recent tariff period is for gas distribution (2020-25), issued in December 2019.

2. Rate of return

a. The overall rate of return

391. ARERA uses a real pre-tax WACC. ARERA's WACC methodology is based on the CAPM and distinguishes between sector-specific parameters and base parameters:

a. **Sector specific parameters**. Sector specific parameters are the beta and the gearing. The beta is updated independently for each sector at the beginning of a new regulatory tariff period (which may not coincide with the WACC regulatory period). The gearing is updated at the same time for all sectors at the beginning of each WACC regulatory sub-period, but may in future switch to the sector-specific tariff review.

b. **Base parameters**. All other WACC parameters are common to all regulated sectors. ARERA sets the total market return used to derive the market risk premium, and the debt premium used to calculate the cost of debt at the beginning of the WACC regulatory period and for the full 6-years. ARERA sets and updates inflation, risk free rate and market risk premium at the beginning of each 3-years WACC regulatory sub-period.

392. ARERA determines revenue controls based on a regulatory asset base indexed to inflation and a real pre-tax WACC. ARERA calculates the real pre-tax WACC as the weighted average between the real cost of equity and the real cost of debt, with an additional adjustment factor which allows for recovery of taxes on nominal profits.[250] The methodology also distinguishes between a rate for the tax shield and the overall tax rate used to convert post-tax returns into pre-tax values, as interest expenses are not fully tax deductible under Italian tax legislation. Table 14 below provides a summary of the calculation of the real pre-tax WACC currently applied

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[249] ARERA, Deliberations 639/2018/R/COM, 654/2015/R/eel, 575/2017/R/gas, 653/2017/R/gas, 639/2018/R/com, 114/2019/R/gas, 419/2019/R/gas, 474/2019/R/gas e 570/2019/R/gas. The updated version is available at the link: https://www.arera.it/allegati/docs/15/583-15tiwacc.pdf

[250] The adjustment is necessary because ARERA takes a non-standard approach to calculating the real cost of equity. The CAPM yields a nominal post-tax cost of equity which must be first converted into nominal pre-tax before it is converted to real. ARERA instead calculates a "post-tax" real cost of equity by simply adding a real risk free rate to the equity risk premium. This approach leads to a lower real pre-tax cost of equity than if one first converts the nominal post-tax cost of equity into nominal pre-tax and then converts the nominal pre-tax into a real pre-tax cost of equity. The adjustment factor ensures the equivalence of the two methods.

by ARERA to the regulated electricity and gas infrastructure sectors. The rate for tax shield tc_p is shown in row [13] and the overall tax rate (T_P) is shown in row [12].

Table 14
Summary of ARERA's Current WACCs

			Electricity		Gas				
			Transmission [A]	Distribution [B]	Storage [C]	Regasification [D]	Transport [E]	Distribution [F]	Metering [G]
Nominal risk-free rate (RFn)	[1]	Notes	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%
Inflation rate in RFR (isrn)	[2]	Notes	1.62%	1.62%	1.62%	1.62%	1.62%	1.62%	1.62%
Real risk-free rate (RFr)	[3]	Notes	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Country Risk Premium (CRP)	[4]	Notes	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%	1.39%
Debt risk premium (DRP)	[5]	Notes	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Real cost of debt (Kdr)	[6]	[3]+[4]+[5]	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%
Total Market Return (TMR)	[7]	Notes	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Equity Risk Premium (ERP)	[8]	[7]-[3]	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
Equity Beta (βlevered)	[9]	Notes	0.616	0.686	0.891	0.922	0.641	0.706	0.706
Real cost of equity (Ker)	[10]	[3]+[4]+[8]x[9]	5.28%	5.66%	6.79%	6.96%	5.42%	5.77%	5.77%
Gearing (g)	[11]	Notes	50.00%	50.00%	50.00%	50.00%	50.00%	44.40%	44.40%
Tax rate (T)	[12]	Notes	31.00%	31.00%	31.00%	31.00%	31.00%	31.00%	31.00%
Tax shield (tc)	[13]	Notes	24.00%	24.00%	24.00%	24.00%	24.00%	24.00%	24.00%
Expected inflation rate (ia)	[14]	Notes	1.70%	1.70%	1.70%	1.70%	1.70%	1.70%	1.70%
Tax adjustment factor (F)	[15]	Notes	0.46%	0.46%	0.46%	0.46%	0.46%	0.49%	0.49%
WACC, real pre-tax	**[16]**	Notes	**5.6%**	**5.9%**	**6.7%**	**6.8%**	**5.7%**	**6.3%**	**6.3%**

Notes:

ARERA updates its TI-WACC decision every time one of the WACC parameters has been updated. All WACC parameters in the table reflect the parameters reported in the most recent version of the TI-WACC decision published on ARERA's website. See ARERA, TIWACC 2016-2021, Version approved with decision 583/2015/R/com and modified with decisions 654/2015/R/eel, 575/2017/R/gas, 653/2017/R/gas, 639/2018/R/com, 114/2019/R/gas, 419/2019/R/gas, 474/2019/R/gas e 570/2019/R/gas ("TI-WACC Decision").

[1], [2], [4], [9], [11], [12], [13], [14]: ARERA, TI-WACC Decision, pp. 8-9.

[3]: Maximum value between (([1]-[2])/(1+[2])-1) and 0.50%.

[5], [7]: ARERA, TI-WACC Decision 2016-2021, p. 5.

[15] = ([14]/(1+[14]))x([12]-[13]x[11])/(1-[12]).

[16] = ([6]x[11]x(1-[13]))/(1-[12]))+([10]x(1-[11])/(1-[12]))+[15].

b. Cost of debt

393. ARERA calculates the cost of debt as the sum of (i) the real risk free rate, (ii) the country risk premium, and (iii) a notional debt premium, which ARERA set equal to 0.5% for the 2016-2021 period, applicable to all companies and all sectors. The TIWACC decision does not explain how the debt premium was calculated. However, the consultation documents clarify that the value was based on the debt premium observed for a representative sample of companies operating in the regulated gas and electricity sectors. The debt premium allowance included in the WACC is therefore not related to the cost of debt of any specific company. Furthermore, regulated companies in the electricity and gas sectors are not subject to any form of claw-back or compensation in case their cost of debt is different from the one included in the WACC.

394. The real cost of debt, calculated as the sum of three components described above, is converted into a real pre-tax cost of debt by multiplying it by 1 minus the tax shield and dividing it by 1 minus the tax rate.

c. Cost of equity

395. ARERA calculates a real post-tax cost of equity as the sum of a real risk free rate, a country risk premium, and an equity risk premium. ARERA applies a floor of 0.5% to the real risk free rate, then adds a country risk premium (based on the spread between Italian and German government bond yields) and the equity risk premium (the sector-specific equity beta multiplied by the market risk premium). The real post-tax cost of equity is converted into real pre-tax cost of equity by dividing it by 1 minus the tax rate.

Equity beta

396. ARERA selects the beta independently for each regulated sector during the sector tariff review, but based on a common methodology set out in the TIWACC decision.

397. ARERA estimates the equity and asset betas for a group of comparator companies operating in high-rated Eurozone countries. ARERA explains that the betas must be estimated using a reference period of at least two years. ARERA does not specify whether the estimate should be based on daily or weekly returns. Rather, they consider multiple estimates during the consultations before making a determination.

398. ARERA selects an asset beta for the relevant sector based on the asset betas calculated for the comparator group.[251] The sector-specific equity beta is then

[251] ARERA has a certain flexibility in the choice of the sample of comparators and of the asset beta. For example, to ensure that a sufficient number of companies are included, ARERA may decide to include in the sample companies that do not exclusively operate the regulated activity object of tariff review.

calculated by re-levering the sector-specific asset beta based on a notional gearing and using the Modigliani-Miller formula.[252]

Market Risk Premium

399. ARERA calculates the MRP based on a Total Market Return (TMR) methodology, where the MRP is calculated as the difference between the TMR and the real risk free rate. The assumption underlying the TMR methodology is that the expected total return to equity is relatively stable in real terms, and that the expected MRP adjusts over time to reflect changes in the real risk free rate. In 2015, ARERA set the TMR at 6% for the 2016-2021 period, which was calculated as a weighted average of the geometric and arithmetic means (20% geometric, 80% arithmetic) of the real return to equity in high rating European countries calculated over the period 1900-2014. Subtracting a real risk free rate of 0.50% resulted in a market risk premium of 5.5%.

Risk free rate

400. To derive the real risk-free rate, ARERA first calculates a nominal risk free rate based on the one-year average yield of 10-year government bonds in a number of double or triple A-rated countries in the Eurozone, currently Germany, France, The Netherlands and Belgium. Italian government bonds are currently not considered. ARERA then converts the nominal rate into real terms based on forecast inflation derived from inflation rate swap contracts in the Eurozone. ARERA then applies a floor of 0.5% to the real risk free rate. Given the extremely low yields of 10-year government bonds, the 0.5% floor has been binding.

d. Gearing

401. ARERA determines the sector-specific notional gearing applicable to all companies operating in the sector. ARERA motivates this approach by expressing the intention to align the values of the notional gearings with those used by other European energy regulators, and towards a maximum value of 50%. For the WACC sub-period 2019-2021, ARERA set the value of the gearing at 50% for all regulated industries, based on a review of notional gearing used by other regulators, with the exception of the distribution and metering of natural gas, where it chose to apply a gearing of 44.4%.

402. The gearing considered in the calculation of the WACC is therefore not related to the financial structure of any specific company. Furthermore, regulated companies in the electricity and gas sectors are not subject to any form of claw-back or compensation in case their gearing level is different from the one included in the WACC.

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252 The sector-specific equity beta is equal to: $\beta_s^{equity} = \beta_s^{asset}\left[1 + \left(1 - tc_p\right)\frac{g_s}{1-g_s}\right]$, where β_s^{asset} is the sector-specific asset beta, tc_p is the tax shield and $g_s$is the sector-specific notional gearing.

e. Treatment of tax and inflation

403. As mentioned above, the WACC methodology makes a distinction between the tax rate to be used for the tax shield and overall tax rate used to convert post-tax cost of equity and debt into pre-tax values. This is due to the fact that in Italy there are both a national corporate income tax ("IRES") and a regional tax on production activities ("IRAP"), and interest expenses are not tax deductible under the regional corporate income tax.

404. ARERA also applies a tax adjustment factor to allow for the recovery of taxes on nominal profits. The adjustment is necessary because ARERA takes a non-standard approach to calculating the real cost of equity. The CAPM yields a nominal post-tax cost of equity which must be first converted into nominal pre-tax before being converted into real pre-tax. Instead, as shown in Table 14, ARERA calculates a real post-tax cost of equity as the sum of a real risk free rate and the equity risk premium. This approach leads to a lower real pre-tax real cost of equity than if one first converts the nominal post-tax cost of equity into nominal pre-tax and then converts the nominal pre-tax into a real pre-tax cost of equity. ARERA's adjustment factor guarantees the equivalence in results with the standard method of calculating the CAPM cost of equity in nominal post-tax terms and then converting it first into a nominal pre-tax and then into a real pre-tax cost of equity.

f. Imputation tax credits

405. Not applicable

g. Other factors

406. Because the risk free rate is calculated based on the government bonds of countries in the Eurozone with high credit ratings, ARERA includes a country risk premium for Italy. The country risk premium applies to both the cost of equity and the cost of debt. For the first WACC regulatory sub-period (2016-2018), ARERA set the country risk premium equal to 1% based on the spread between the yields of 10-year government bonds in Italy and Germany.[253] ARERA further established that the country risk premium should be updated in the second regulatory sub-period (2019-2021) based on a formula that considers the change in the spread between the yields of 10-year government bonds in Italy and Germany.[254]

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[253] ARERA does not provide details about the calculation. The 1%, however, corresponds to the average spread between the yields of 10-year government bonds in Italy and Germany over the period Oct 2014-Sept 2015.

[254] The country risk premium is updated between WACC regulatory sub-periods only in case the change in the spread between sub-periods is more than 20%. Applying this mechanism, ARERA updated the country risk premium for the WACC period 2019-2021 from 1% to 1.4%.

F. The New Zealand Commerce Commission

1. The regulatory framework

407. The New Zealand Commerce Commission (NZCC) is the regulatory body responsible for regulating gas and electricity transmission and distribution (as well as some airport services, telecoms and the dairy sector).[255]

a. Objective

408. NZCC's central goal is to promote the long-term benefit of consumers by promoting competitive market outcomes.[256]

409. The electricity sector consists of a single state-owned transmission network operator, Transpower, and 29 Electricity Distribution Businesses (EDBs), 17 of which are investor-owned and 12 which are consumer-owned. The NZCC sets prices for the investor-owned EDBs and Transpower, as well as one gas transmission business (First Gas) and four gas distribution businesses (GPBs).

410. The NZCC publishes "price-quality path" regulations at the beginning of each regulatory period, where it determines the revenue controls and appropriate quality standards (e.g., for interruptions). More specifically, the NZCC publishes three different price-quality regulatory schemes. All three schemes have rate of return parameters set in the same way, but differ in other details (one interesting feature of the DPP scheme is that there is no "application" or "proposal" step, but rather the NZCC's process relies entirely on information that the utilities are required to disclose annually). The three schemes are:

a. The Default Price-quality Path (DPP) regulation for GPBs and investor-owned EDBs based on a 5-year regulatory period.

b. The Individual Price-quality Path (IPP) regulation for Transpower, which typically is based on a regulatory period of 5 years but allows for a 4-year period.

c. GPBs and EDBs can apply for a Customised Price-quality Path (CPP) if they consider that the DPP is not appropriate, given the specific circumstances facing that business. CPPs apply for regulatory periods of 3 to 5 years. Currently two EDBs are subject to a CPP.

411. In addition to the price-quality path regulations, the NZCC publishes annual Information Disclosure (ID) regulations, which requires all entities in regulated industries (including consumer-owned EDBs) to publish information about their financial and technical performance.

412. The price-quality path approach is similar to frameworks in other jurisdictions (Great Britain, Australia) with five-year revenue caps, although the NZCC relies to

[255] Part 4 of the Commerce Act of 1986 as amended by the Commerce Amendment Act of 2008, Section 52, p. 9.

[256] *Ibid*, Section 52A, p. 9.

a greater extent on standardized annual reporting of relevant regulatory accounting information, rather than a "proposal" from the utility.

413. Following a consultation process with relevant stakeholders, the NZCC publishes the price-quality path determination papers, which are based upon methodologies set out in the Input Methodology (IM) papers, with detailed reasoning contained in the IM Reasons papers.

b. Timing and sequencing

414. The price-quality path process determines authorised revenues for a five-year period (or 3–5 years for a CPP), using a building blocks approach. A common methodology is used to determine the authorised rate of return within each price-quality path for each regulated service. The initial cost of capital methodology was originally set in 2010 and is contained in Chapter 6 and Appendix E of the Electricity Distribution and Gas Pipeline Services Input Methodologies Reasons Paper.[257] All other IMs reference this source for the cost of capital methodology. Only the risk-free rate and average debt premium are updated for WACC determinations for every regulatory period for both the price-quality path and ID regulation. All other parameter values for estimating the WACC are fixed while the relevant IMs are in force. All IMs must be revised at least every 7 years.[258] The most recent methodology revision of both the DPP and Cost of Capital IMs took place in 2016.[259] Thus the 2016 review is the current rate of return methodology (and determined all parameters, as well as the methodology for subsequent determination of the risk free rate and debt premium).

415. There have been various minor and consequential changes, and a later consolidated decision was published on March 20, 2020.[260] However, these changes did not alter the rate of return parameters.

2. Rate of return

a. The overall rate of return

416. The allowable return on capital estimation is based on a WACC methodology. The NZCC calculates both a nominal vanilla WACC for the purposes of setting prices (since tax expense is directly forecast) and a nominal post-tax WACC for information purposes. A post-tax WACC estimate is included since it is the more

257 NZCC, Input Methodologies (electricity distribution and gas pipeline services) reasons paper, December 2010.

258 Part 4 of the Commerce Act of 1986 as amended by the Commerce Amendment Act of 2008, Section 52Y, p. 24.

259 NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016.

260 NZCC, Electricity Distribution Services Default Price-Quality Path Determination 2020, March 20, 2020.

well-known WACC variant and more investors would be familiar with it. Similar to the AER, the NZCC targets a real return, and the rate base is adjusted for inflation.

417. The NZCC reports a WACC that is the mid-point estimate of a WACC range, which is intended to reflect estimation error. A standard error for the WACC is estimated based on point-estimates of the standard errors for the asset beta, debt premium, and the tax adjusted market risk premium (TAMRP) parameters. The WACC standard error was set at 0.0101 for Transpower/EDBs.[261] From this standard error a range of WACC estimates including the 25th, 67th, and 75th percentile are determined as shown in Table 15 below.[262]

Table 15
WACC estimate percentile range

25th percentile	mid-point WACC - 0.674 x standard error
67th percentile	mid-point WACC + 0.44 x standard error
75th percentile	mid-point WACC + 0.674 x standard error

Sources:
"NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016."

418. For all price-quality path regulations the 67th percentile estimate of the vanilla WACC is used to set allowable revenues.[263] The decision to use an above-midpoint WACC was made to "reduce the risk that the estimate was lower than the true (but unobservable) return required by investors".[264] Additionally, the NZCC held the view that the "costs to consumers of using a WACC that was too low would be greater than the costs of using a WACC that was too high."[265] Initially the 75th percentile WACC estimate was used however this was later challenged at the High Court in 2014 which resulted in a lowered estimate to the 67th percentile.[266]

419. Table 16 shows the most recent parameter values used in the price-quality path regulations.

[261] NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016, Table X1, p 624.

[262] *Ibid.*

[263] NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016, Section 18, p. 631.

[264] NZCC, Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services Reasons paper, October 30, 2014, p. 15.

[265] NZCC, Input methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper, December 2010, Section H13.44, p. 588.

[266] NZCC, Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services Reasons paper, October 30, 2014.

Table 16
Most recent WACC decisions for price-quality path regulations: Regulatory periods 2020-2025 (Transpower and EDBs)

Parameter	Methodology	Source for Estimate	Estimate
Risk-free rate	[1] Linearly-interpolated, annualized bid yield to maturity on NZ Govt bonds with maturity matching the regulatory period.	Current Determination.	1.12%
Average debt premium	[2] 5- year rolling average of difference between [1] and yield on BBB+ corporate bonds with maturity matching the regulatory period.	Current Determination.	1.60%
Leverage	[3] Assumed based on the average leverage of a survey of 79 listed utility companies in NZ, Australia, and the US.	2016 IM Review.	42%
Asset beta	[4] Assumed based on middle value of survey results of de-levered equity betas of comparable businesses.	2016 IM Review.	0.35
Equity beta	[5] [4] + ([4] - debt beta) x [3]/(1 - [3])	2016 IM Review.	0.60
Tax adjusted market risk premium (TAMRP)	[6] Composite rate over the regulatory period reflecting average expected long-term returns above the risk free rate on a portfolio of NZ equities.	2016 IM Review.	7.00%
Average corporate tax rate	[7] Taken from statutory tax rates.	2016 IM Review.	28%
Average investor tax rate	[8] Maxmimum prescribed investor tax rate under PIE tax regime.	2016 IM Review.	28%
Debt issuance costs	[9] Based upon estimates of cost of issuing publicly-traded bonds.	2016 IM Review.	0.20%
Cost of debt	[10] [1] + [2] + [9]	Current Determination.	2.92%
Cost of equity	[11] [1] x (1 -[8]) + [5] x [6]	Current Determination.	5.00%
Standard error of WACC	[12] Based upon a complex analyitical approach which estimates and combines individual WACC parameters point-estimates of standard errors into a plausible WACC range.	2016 IM Review.	0.0101
Mid-point vanilla WACC	[13] [10] x [3] + [11] x (1 - [3])	Current Determination.	4.13%
Mid-point post-tax WACC	[14] [10] x (1- [7]) x [3] + [11] x (1 - [3])	Current Determination.	3.78%
67th percentile vanilla WACC	[15] [13] + 0.44 x [12]	2016 IM Review.	4.57%
67th percentile post-tax WACC	[16] [14] + 0.44 x [12]	2016 IM Review.	4.23%

Sources:
"Current determination": Transpower and EDBs = NZCC, Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths
"2016 IM Review": NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016.

b. Cost of debt

420. The cost of debt is calculated by adding to the risk-free rate a debt premium and an allowance for the cost of issuing debt.[267] To confirm that the NZCC's estimates of the calculated cost of debt are realistic, the estimate is compared to confidential information provided by the regulated companies of their actual costs of debt financing.

[267] The cost of debt methodology is described in chapter 3 of the cost of capital paper (part of the consolidated reasons paper for the 2016 IM review, 20 December 2016). The NZCC explains its current approach with reference to the decisions taking in the original 2010 IMs determination, so we also cite the 2010 reasons papers.

421. The risk free rate is based on yields of New Zealand government bonds with a term to maturity matching the regulatory period (5 years for DPP and IPP or 3 to 5 years for CPP).

422. The risk free rate period was chosen to match the length of the regulatory period to allow for utilities to earn a normal return while being adequately compensated for interest rate risk, yet not being over-or-under compensated (depending on the yield curve) which was determined could occur if longer a term was considered.[268]

423. The debt premium is the difference between the risk free rate and the yield on publicly traded corporate bonds of similar businesses (to EDBs, Transpower, and GPBs) with a BBB+ S&P long-term credit rating and a term to maturity that matches the regulatory period (normally five years).[269] The debt premium is calculated based on a 5-year average of the debt premium of the current year and the previous four years.[270] For the Debt Premium Reference Year (DPRY) 2020 for Transpower and EDBs this was determined as 1.60%. The DPRY 2020 was compared to the Nelson-Siegel-Svennson (NSS) model estimate of the debt premium of 1.52% to conclude that the DPRY is a realistic measure.[271] The NSS is a polynomial financial model which is widely used by central banks to estimate yield curves. Here, instead of the yield curve, the NZCC repurposes the NSS model to estimate the "debt premium curve." [272]

424. Additionally, debt issuance costs are granted as an additional allowance for the costs associated with raising debt. The debt issuance costs were set as 0.2% in the 2016 IM review[273] (reduced from 0.35% in the 2010 IMs).[274]

425. The NZCC's reasoning for measuring the debt premium in line with the regulatory period is the same its reasoning for doing the same with the risk free rate. Any costs arising from issuing debt for terms greater than the regulatory period are given a separate allowance known as the Term Credit Spread Differential (TCSD). The TCSD adjustment only applies to regulated entities which issue debt with tenors greater than the regulatory period to hedge their refinancing risk. The TCSD is executed exogenously from the WACC calculation and encompasses the costs

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[268] NZCC, Input Methodologies (electricity distribution and gas pipeline services) reasons paper, December 2010, Table 6.1, p. 134.

[269] *Ibid.*

[270] NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016, Table X1, p 624.

[271] NZCC, Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path, September 25, 2019, Table 5, p. 6.

[272] NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016, Attachment D, pp 876-878.

[273] NZCC, "Cost of capital determination for disclosure year 2020", July 31, 2019, Table 5, p. 6.

[274] NZCC, Input Methodologies (electricity distribution and gas pipeline services) reasons paper, December 2010, Table 6.1, p. 134.

arising from issuing longer maturity debt (terms longer than 5 years) which cannot be hedged via interest rate swaps.[275] Among the utilities that receive the TCSD allowance are Transpower (electricity transmission), Vector (gas distribution), and Powerco (electricity/ gas distribution).[276]

c. Cost of equity

426. The Cost of Equity is estimated using the Simplified Brennan-Lally CAPM.[277] The simplified Brennan-Lally CAPM is used as this is a New Zealand specific model which best fits the features of the New Zealand equity market and taxation system and due to its widespread use in NZ.[278] The simplified Brennan-Lally CAPM assumes that dividends are fully imputed therefore investors receive full benefits from dividend imputation tax credits, investors incur no tax on capital gains, and the New Zealand capital markets are completely segregated from overseas capital markets.[279]

Equity beta

427. A list of 70 listed utility companies in NZ, Australia and the US are used to estimate equity beta. This list came from a survey carried out for the 2016 IM review.[280] Equity betas are estimated using a range of daily, weekly and monthly estimates across different time windows. The individual equity beta estimates are de-levered, and an unweighted average asset beta calculated. The asset beta is then relevered at the leverage determination made by the NZCC (see "Gearing" discussion below).[281] The asset beta as determined by the middle estimate of the survey was set at 0.35 for Transpower/EDBs to result in equity betas of 0.60.[282]

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275 NZCC, Input Methodologies (electricity distribution and gas pipeline services) reasons paper, December 2010, Section X29, p. viii.

276 EDB Information Disclosure 2019 (Vector), August 30, 2019, Schedule 5c, p. 14; EDB Information Disclosure 2019 (Powerco), August 22, 2019, Schedule 5c, p. 15; Transpower Information Disclosure 2019, 30 June 2019, Excel tab TP1: ROI and profit.

277 The cost of equity methodology is described in chapter 4 of the cost of capital paper (part of the consolidated reasons paper for the 2016 IM review, 20 December 2016). The NZCC explains its current approach with reference to the decisions taking in the original 2010 IMs determination, so we also cite the 2010 reasons papers.

278 NZCC, Input Methodologies (electricity distribution and gas pipeline services) reasons paper, December 2010, Section X31, p. viii.

279 NZCC, Cost of Capital Straw Person Example – Electricity distribution industry, p. 1.

280 NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016, Section 224.5, p. 65.

281 NZCC, Input Methodologies (electricity distribution and gas pipeline services) reasons paper, December 2010, p. 157-161.

282 NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016, Section 262-265, p. 59-60.

Market Risk Premium

428. Due to the particularities of the simplified Brennan-Lally CAPM, a Tax Adjusted Market Risk Premium (TAMRP) is estimated in place of the more widespread MRP. The TAMRP was assumed as 7%, which reflects the average return of owning a portfolio of New Zealand equity investments of average risk. This was chosen from data from a range of sources drawing from both historical and forecast estimates of the return on equity investments with average risk. It is consistent with the average assumption used by New Zealand investment banks. [283]

Risk free rate

429. See the discussion under the cost of debt.

d. Gearing

430. The leverage parameter is assumed at 42%, based on the same survey used to estimate equity beta.[284]

e. Treatment of tax and inflation

431. The treatment of tax is based on the principle that "taxation should generally be consistent with flat aggregate prices in real terms, unless economic depreciation suggests otherwise."[285] Tax costs are estimated using a "tax payable" approach for gas transmission services and a "modified deferred tax" approach for all other services.

432. For the purpose of converting the vanilla WACC into a post-tax WACC, the corporate tax rate is fixed at 28% and changes in the corporate tax rate (if any) will flow through to future post-tax WACC estimates automatically.[286] The investor tax rate is the maximum prescribed investor tax rate under the Portfolio Investment Entities (PIE) tax regime, which is currently 28% and any changes will flow through to future post-tax WACC estimations.[287]

433. As mentioned above, NZCC targets a real return, similar to the AER. The Regulatory Asset Base is adjusted for inflation annually by indexing to the Consumer Price Index (CPI). Revenues are also indexed to CPI.

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283 NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016, Topic Paper 4 – Cost of Capital, pp. 126-137.

284 NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016, Section 224.5, p. 65.

285 *Ibid,* Section 5.2.6, p. 126.

286 NZCC, Input Methodologies Review Decisions Consolidated Reasons Papers, December 20, 2016, Section 262-265, Table 6.1, p. 135.

287 *Ibid*, Table 6.1, p. 134.

f. Imputation tax credits

434. As discussed above, the cost of equity is estimated using the Simplified Brennan-Lally CAPM, which assumes that dividends are fully imputed therefore investors receive full benefits from dividend imputation tax credits, investors incur no tax on capital gains, and the New Zealand capital markets are completely segregated from overseas capital markets.[288]

g. Other factors

435. Debt issuance costs are granted as an additional allowance for the costs associated with raising debt. The debt issuance costs were set as 0.2% from the 2016 IM review[289] (originally 35 bps/0.35% in the initial estimation[290]) and are not updated each regulatory period.

436. Further, as mentioned above, any costs arising from issuing debt for terms greater than the regulatory period are given a separate allowance (the Term Credit Spread Differential).

G. The UK Office for Gas and Electricity Markets

1. The regulatory framework

437. Ofgem, the Office for Gas and Electricity Markets, is the agency responsible for the regulation of gas and electricity transmission and distribution in England, Wales, and Scotland.[291]

a. Objective

438. In regulating these activities, Ofgem's principal objective is "to protect the interest of consumers […] wherever appropriate by promoting effective competition." It shall do so "having regard to (a) the need that all reasonable demands for [gas and electricity] are met; and (b) the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under [the relevant legislation]."[292] The objective of Ofgem's price reviews is to meet "the

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[288] NZCC, Cost of Capital Straw Person Example – Electricity distribution industry, p. 1.

[289] NZCC, "Cost of capital determination for disclosure year 2020", July 31, 2019, Table 5, p. 6.

[290] NZCC, Input Methodologies (electricity distribution and gas pipeline services) reasons paper, December 2010, Table 6.1, p. 134.

[291] Ofgem regulates 14 electricity and 8 gas network companies, as well as 3 electricity and 1 gas transmission network, all of which are privately owned or listed. Ofgem also regulates the electricity system operator.

[292] Gas Act 1986, Section 4AA and Electricity Act 1989, Section 3A. The two pieces of legislature are updated in the Utilities Act 2000.

needs of consumers and network users", maintain "a safe and resilient network", and deliver "an environmentally sustainable network".[293]

439. Ofgem considers innovation and output objectives for the regulated companies and authorised revenues are set such that an efficient operator can recover its costs, including a reasonable return on the capital employed.

440. While Ofgem must have regard to financeability, it does so with respect to an efficient operator. It makes general recommendations for actions companies can take to address financeability concerns, but has abandoned specific support mechanisms.[294]

441. Ofgem collaborates with other UK regulators through the UK Regulators Network (UKRN), which often commissions studies by academics and practitioners to get regulatory advice. In particular, a study by Wright et al set out specific recommendations, which Ofgem makes reference to in its determinations on the various elements of the authorised return.[295]

442. Ofgem also manages the tender process for offshore transmission licenses. In the UK, offshore transmission operators ("OFTOs") are selected through auctions where, so far, participants have bid for transmission assets built by the wind farm developers, although the tender system also allows for a model where OFTOs are responsible for construction as well. The participants' bids consist of revenue requests over a fixed period of 25 years[296] covering the costs of acquiring the transmission asset, the operation of the asset, and availability incentives.[297] The nature of OFTO assets and their operation is different from, for example, running a distribution network. In addition, apart from inflation indexation, the OFTO revenues are fixed (there is no revenue reset during the 25 year term). Nonetheless, Ofgem has used the auction results to infer market-based cost of capital information that it used to inform setting of authorised returns in its price control process for the onshore operators.

443. In our review of Ofgem's methodology below, we rely on Ofgem's May 2019 method decision. While Ofgem has made certain methodological decisions on how it would estimate parameters, it refers to the estimates published in May 2019 as working assumptions.[298]

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293 Ofgem, "RIIO-2 Sector Specific Methodology – Core Document", May 2019, ("Ofgem RIIO-2 – Core Document"), p. 9.

294 For example, Ofgem had earlier considered developing a cash flow floor that would provide further assurances to debt holders. Ofgem RIIO-2 – Core Document, pp. 130-132.

295 Wright et al, "Estimating the cost of capital for implementation of price controls by UK Regulators", 2018.

296 Earlier tenders set revenues over a 20-year term. PwC, "Offshore Transmission Market Update", October 2018, p. 10.

297 PwC, "Offshore Transmission Market Update", October 2018, p. 14.

298 See, eg, Ofgem RIIO-2 – Finance, p. 7.

b. Timing and sequencing

444. Ofgem determines revenue requirement and the associated rate of return at the beginning of each 5-year regulatory period.

445. Ofgem's current price review, which will apply to the regulatory period 2021-25[299] and is known as RIIO-2 under the second "revenue = incentives + innovation + outputs" framework, started with an open letter in July 2017. Ofgem later published a framework decision in July 2018, and a method decision (the sector specific decision) in May 2019. At all stages, Ofgem consults with the relevant stakeholders. Draft and final determinations will be published in June and November 2020, respectively.[300] The regulated companies, retailers and customer groups may appeal Ofgem's decisions to the Competition and Markets Authority.[301] Although Ofgem will tend to make major methodology choices early in its decision-making process, and focus on details later, formally there are no binding decisions prior to the final determination of authorised revenues just before the start of the revenue period. Thus, for example, we would anticipate that the method for the electricity distribution determination will closely follow the method for electricity transmission, gas transmission and gas distribution, there is no requirement that it should do so.

2. Rate of return

a. The overall rate of return

446. Ofgem sets revenue allowances based on a regulated asset value (RAV) indexed to inflation and an authorised return in real terms.

447. Ofgem calculates a real vanilla WACC.

a. The cost of debt is calculated based on a trailing average of the yield of comparable debt. It is updated every year based on outturn market data. Ofgem refers to this approach as full indexation.[302]

b. Ofgem calculates the cost of equity based on the CAPM. Ofgem also compares its headline number with four crosschecks: market-to-asset ratios,[303] bids from OFTO tenders, forecasts from investment managers and advisors (on returns on the total market), and infrastructure fund discount rates.[304] Ofgem finds that its crosschecks

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299 The regulatory period for electricity distribution companies starts in 2023. The May 2019 method decision covers electricity and gas transmission, gas distribution, and the electricity system operator.

300 Ofgem RIIO-2 – Core Document, pp. 12-13.

301 Changes to the appeals framework are currently being considered. Ofgem RIIO-2 – Core Document, p. 12.

302 Ofgem RIIO-2 – Finance, p. 15.

303 The market-to-asset ratio (MAR) is the ratio of the market value of a company to its regulated asset value. Ofgem uses this metric to assess whether companies expect to earn returns exceeding their cost of capital.

304 Ofgem RIIO-2 – Core Document, pp. 124-126.

support its CAPM measure. However, based on the crosschecks it decides to include a 0.1% uplift to its cost of equity estimate.[305] Ofgem also updates its cost of equity for changes in the risk-free rate. The risk-free rate is determined every year based on market rates for the previous year, which implies that the cost of equity changes annually. Ofgem refers to this approach as equity indexation.[306]

448. Table 17 summarises methodologies as well as point estimates as published in Ofgem's May 2019 methodology decision. The estimates may be updated in its final determinations due at the end of 2020.

Table 17
Summary of Ofgem Authorised Return

Measure		Source	Estimate	Methodology
Allowed Return on Debt (pre-tax)	[1]	Finance p. 19	1.93%	11-15 year rolling average based on bond indices
Risk-free Rate	[2]	Finance pp. 26, 30	-0.75%	Contemporaneous 20-year inflation-indexed government bonds plus forward curve uplift
Market Risk Premium	[3]	[4]-[2]	7.25%	
Total Market Return	[4]	Finance pp. 31-42	6.50%	Assumption based on multiple sources (historic averages and investor studies)
Raw Beta	[5]	Finance pp. 56-57, 152-161	0.63	Based on longer term (5 years+) averages for 5 UK comparators
Adjusted Gearing	[6]	Finance pp. 56-57, 152-161	49.80%	Net debt over equity with discretionary adjustment
Debt Beta	[7]	Finance pp. 56-57, 152-161	0.125	Assumption based on external studies
Asset Beta	[8]	[5]x(1-[6])+[7]x[6]	0.38	Unlevered beta using net debt to equity for 5 UK comparators
Notional Gearing	[9]	Finance pp. 56-57, 152-161	60%	Working assumption
Notional Equity Beta	[10]	([8]-([7]x[9]))/(1-[9])	0.75	
Cost of Equity Uplift	[11]	Finance, p.66	0.10%	Assumption based on crosschecks
Cost of Equity (post-tax)	[12]	[2]+[4]x[10]+[11]	4.80%	
Expected Outperformance	[13]	Finance p. 77	0.50%	Based on evidence from other price controls
Allowed Return on Equity	[14]	[12]-[13]	4.30%	
Allowed Return on Capital (vanilla)	[15]	[1]x[9]+[14]x(1-[9])	2.88%	

Notes and sources:
Expressed in CPIH-adjusted terms.
Note that the cost of equity is calculated as the mid point between high and low estimates. Mid point estimates shown in table may not exactly add up.
Ofgem, RIIO-2 - Sector Specific Methodology - Finance, May 2019.

b. *Cost of debt*

449. Under its previous framework, RIIO-1, Ofgem calculated the cost of debt using 10-year rolling averages of outturn market rates. It used the iBoxx indices reflecting the cost of debt of A and BBB rated non-financial companies considering maturities of at least 10 years. Similarly to Ofgem's approach to the cost of equity, the cost of debt will be updated every year. It refers to this approach as full indexation.[307]

450. As a working assumption, Ofgem proposes using the above mentioned iBoxx indices but with a longer averaging period of 11-15 years, which external consultants have suggested provides a better match to expected costs of debt.[308] Ofgem emphasises that this working assumption is purely illustrative and not a methodology decision.

305 Ofgem RIIO-2 – Finance, p. 66.
306 Ofgem RIIO-2 – Finance, p. 30.
307 Ofgem RIIO-2 – Finance, p. 9.
308 Ofgem RIIO-2 – Finance, pp. 18-19. An 11-year average for year 1 in the next regulatory period, and 15 years for the last year. In all cases, the average would go back to the end of 2009. Also note

451. It is considering various ways of how to calibrate the index to match the intended result of expected efficient debt costs, both in relation to expected new issuance and "old" debt.[309] This includes the averaging period, the choice and weights of the specific indices used, and a "'wedge' for expected sector old debt cost differential to the index."[310] Ofgem also said: "The calibration will consider Business Plan information regarding expected volume of new debt to be raised in RIIO-2 and will also consider the efficiency of sector old debt. Calibration may exclude inefficiently raised debt and/or complex, unusual or opaque products that would not be contemplated for the notional company."[311] It is not clear how Ofgem would identify "inefficiently raised debt".

452. In its previous price review, RIIO-1, Ofgem did not consider further adjustments arguing that transaction and liquidity costs are offset by the fact that the companies were able to issue debt at rates below the index (referred to as the "halo effect").[312] Ofgem is reconsidering this now.

453. Ofgem performed an analysis of spreads (vis-à-vis gilts) of A/BBB indices and bonds issued by the companies. Based on this Ofgem finds that the "halo effect" has reduced over time to about 10 basis points.[313] As a result, Ofgem considers it appropriate to also account for transaction and liquidity costs explicitly. Ofgem has not provided details on how it will approach this issue but states that it will consider various aspects such as small company premia, actual issuance and liquidity costs in companies' business plans, and the fact that companies also hold shorter term and floating rate debt, which is cheaper than what the long-term index would suggest.[314]

c. Cost of equity

454. Ofgem follows a three-step process to its calculation of the cost of equity whereby it (i) calculates the relevant parameters using the CAPM, (ii) crosschecks the resulting CAPM cost of equity against other approaches and sources, and (iii) assesses the extent to which there is a difference between expected return, i.e. the return it calculates, and the authorised return due to financial incentives within the framework design.[315] Ofgem's cost of equity crosschecks in step 2 result in a 0.1%

that the iBoxx indices themselves contain bonds placed by regulated utilities. Ofgem RIIO-2 – Finance, p. 20.

309 Ofgem (and Ofwat) use the term "embedded debt" to refer to debt already issued before the revenue determination. We use the term "old" debt because when US regulators use the term "embedded debt" they mean that the revenue determination will include the *actual* coupon on the existing debt, whereas Ofgem and Ofwat allow a "historical benchmark" on this existing debt, irrespective of its actual coupon.

310 Ofgem RIIO-2 – Core Document, pp. 119-120.

311 *Ibid.*, paragraph 12.15.

312 Ofgem RIIO-2 – Finance, p. 20.

313 Ofgem RIIO-2 – Finance, pp. 20-21.

314 Ofgem RIIO-2- Core Document, pp. 119-120 and Ofgem RIIO-2 – Finance, pp. 20-22.

315 Also note that an analysis of outperformance is recommended by Wright et al, pp. 73-75.

uplift to its CAPM estimate.[316] Its analyses in step 3 result in a preliminary working assumption to reduce the expected return by 0.5%.[317]

455. Ofgem distinguishes between expected and authorised return. Due to financial incentives, the expected return can be different from that authorised by Ofgem. Ofgem argues that "on the balance of probabilities, investor expectations will be positive and that companies will be expected to outperform regulatory targets."[318] As a working assumption based on evidence from other price controls from both within and outside the energy sector, Ofgem proposes to deduct 0.5% points from its cost of equity for "expected outperformance".[319] Before settling on a final number on expected out- or under-performance in its determinations to be published later in 2020 it intends to consider further evidence including evidence provided by the companies in their business plans.[320]

Equity beta

456. Ofgem has not decided on its exact approach to the estimation of the equity beta. Ofgem indicates that it will estimate raw betas using historical data over periods of at least 5 years using a sample of 5 listed UK utility companies.[321] In a second step, Ofgem would calculate gearing based on the book value of net debt for those comparators and over the same time period considered for the estimation of the raw beta.[322] The average of the comparator gearing is used to unlever the raw beta. Ofgem also considers a debt beta of 0.125 based on various external studies. Considering average raw beta, average gearing and the debt beta, Ofgem obtains an asset beta, which is then relevered using 60% notional gearing as a working assumption.[323]

457. Ofgem also uses evidence from the OFTO tenders as crosschecks on its calculations. OFTO bids indicate the returns requested by the auction participants (because bidders are required to pay a pre-determined lump sum to acquire the assets up front, and bids consist of the corresponding revenues demanded over a 25 year period (with no resets)). Effectively, then bidders are bidding a discount rate. This

316 Ofgem RIIO-2 – Finance, p. 66.

317 Ofgem RIIO-2 – Finance, pp. 77-78.

318 Ofgem RIIO-2 – Finance, p. 67.

319 Ofgem RIIO-2 – Finance, p. 77.

320 Ofgem RIIO-2- - Finance, p. 77. See below for additional details on gearing.

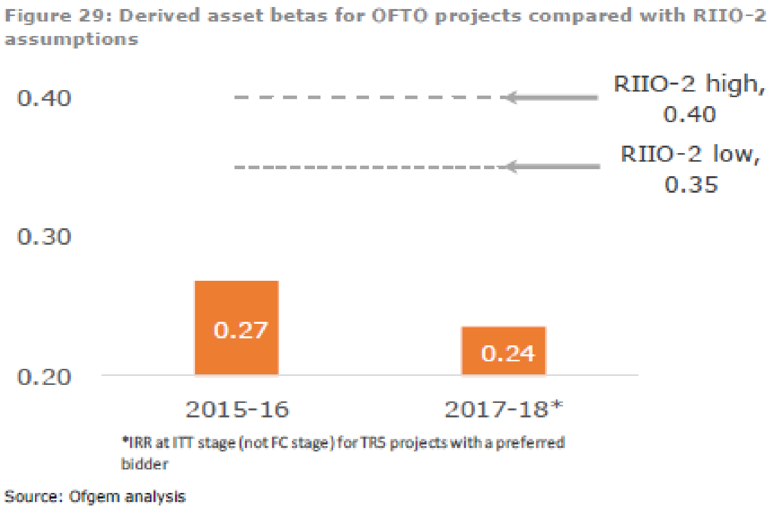
321 Ofgem's uses OLS regression as its main estimation approach, and GARCH as a crosscheck (see Ofgem RIIO-2 – Finance, p. 56). With respect to the list of comparators, Ofgem considers SSE, Severn Trent, United Utilities, National Grid, Pennon (see Ofgem RIIO-2 – Finance, p. 152). Ofgem has not decided on what exact time periods it would use. Its current working assumption range comes from external studies that estimate betas over periods of different lengths from 5 to 17.5 years (see Ofgem RIIO-2 – Finance, p. 42 and 57).

322 Ofgem also considers a market value factor in its estimate of comparator gearing. Ofgem RIIO-2 – Finance, p. 57.

323 Ofgem RIIO-2 – Finance, pp. 42-57 and 152-161.

allows Ofgem to derive asset betas from the bid data of recent tenders and to conclude that they are significantly lower than the asset betas used in its calculation of the cost of capital for the regulated companies subject to the RIIO-2 framework. It argues that this "supports [Ofgem's] position that the asset beta [it] assume[s] for RIIO-2 is not evidently low".[324] Figure 8 reproduces a figure from Ofgem regarding its comparison to the results from OFTO tenders. Ofgem concluded that the OFTO results supported a cost of equity towards the top end of the of the CAPM range.[325]

Figure 8
Asset betas derived from OFTO tenders



Market Risk Premium

458. Ofgem calculates the MRP based on a Total Market Return (TMR) methodology, which measures the MRP as the difference between the historical real TMR and the current or forward-looking real risk free rate. The focus is on the realized market return instead of on the MRP. The assumption underlying the TMR methodology is that the relationship between the real risk-free rate and the real MRP is perfectly negatively correlated. The expected total return to equity is relatively stable in real terms, and that the expected MRP adjusts over time to reflect changes in the real risk free rate.

459. The starting point for Ofgem's determination of the TMR is the above mentioned study by Wright et al, which recommends the use of long-run historical averages and suggests a range of 6-7% in real terms.[326] Ofgem consulted with stakeholders on various issues regarding the TMR in particular:

a. The correct measure for outturn and expected inflation.

b. The conversion between RPI and CPIH real TMR estimates.

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324 Ofgem RIIO-2 – Finance, p. 162.

325 Ofgem RIIO-2 – Finance, para 3.138.

326 Wright et al, p. 8.

c. The calculation of the uplift to convert from geometric to arithmetic returns. The Wright et al study mentioned above recommends calculating a geometric average TMR and adding an uplift to obtain an arithmetic average, which it argues is more appropriate than calculating arithmetic averages directly.[327]

d. The reliability of crosschecks put forward based on the dividend growth model.

e. Additional crosschecks based on forecasts from investor studies.[328]

460. Ofgem argues that the crosschecks it considers confirm the reasonableness of its proposed range for the TMR. In particular, evidence based on the dividend growth model and forecasts from investor studies indicate a lower TMR.[329] Ofgem also considers real returns for the UK and world markets measured in USD, which it argues provide further support of its working assumption of a real TMR in the range 6.25%-6.75%.[330]

461. As for the calculation of the MRP, we understand that the TMR is assumed fixed over the regulatory period, while the MRP changes with the risk-free rate, which is set annually.

Risk free rate

462. Ofgem sets the real risk-free rate annually based on available data prior to the financial year in question.[331] More specifically, the risk-free rate is based on the spot rate for long-term RPI-linked government gilts. The current proposal is to use the average yield for the month of October, but Ofgem will consult further on whether to use a 6-month or 12-month averaging period.[332]

463. Ofgem uses long-term inflation forecasts to convert from nominal to real values. Until recently, the Retail Price Index (RPI) has been the main measure for inflation used in rate setting methodologies. Ofgem has moved from the RPI to the Consumer Price Index including owner occupiers' housing costs (CPIH) as the preferred measure of inflation.[333] In doing so, it follows a decision by the UK Statistics Authority, which no longer considers the RPI a reliable measure of inflation.[334] As Ofgem's May 2019 publication does not reflect final determinations these assumptions are necessarily preliminary. Ofgem uses a working assumption of 2%

327 Wright et al, p. 125.

328 Ofgem RIIO-2- - Finance, pp. 31-42.

329 Ofgem RIIO-2 – Finance, pp. 41-42

330 Ofgem RIIO-2 – Finance, p. 31 and Ofgem,"RIIO-2 – Framework Decision", July 2018, pp. 27-28.

331 Ofgem RIIO-2 – Finance, p. 30.

332 *Ibid.*, paragraph 3.32.

333 Ofgem RIIO-2 – Core Document, p. 132.

334 Ofgem, "RIIO-2 – Framework Decision", July 2018, p. 66. Also see UK Statistics Authority, Assessment of Compliance with the Code of Practice for Official Statistics, The Retail Prices Index, Assessment Report 246, March 2013. While the RPI is still published, it no longer has the designation as an official inflation statistic for technical reasons.

CPIH inflation.[335] As the risk-free rate as one of the parameters feeding into the calculation of various WACC parameters are indexed to the RPI, it also infers an "RPI-CPHI wedge" of 1.049%, to be able to convert between inflation measures.[336]

464. For the headline figure published in its methodology decision, Ofgem adds expected increases in the risk-free rate as indicated by the forward curve for the regulatory period to obtain a cost of equity for the regulatory period. As this measure is in real RPI terms, Ofgem adjusts for expected differences in RPI and CPIH based on the RPI-CPIH wedge.[337] Ofgem is still considering the exact averaging period for the gilt yields, the tenor, the method for obtaining real CPIH values, and the calibration of the cost of equity to changes in the risk-free rate.[338]

d. Gearing

465. Ofgem has not yet finalised all of the details for the current price review (RIIO-2). For the previous price review, RIIO-1, Ofgem set sector-specific levels for notional gearing. For example, it set 55-60% for electricity transmission and 65% for gas distribution.[339] Ofgem considered the actual book value gearing of the regulated companies, financeability, as well as a "return on regulatory equity range".[340] The differences in notional gearing across the sectors reflected Ofgem's view on differences in risk following a comparative assessment of cash flow and investment risk.

466. Ofgem is currently reconsidering the level of gearing in consultation with the regulated companies. While Ofgem does not provide details on how it would go about setting notional gearing, it mentions the importance of companies' business plans and that it expects companies to make risk assessments and advance proposals for notional gearing.[341] Ofgem says it would consider the riskiness of business plans and financeability for its final determination on notional gearing. As a working assumption, Ofgem uses 60%.[342]

335 Ofgem RIIO-2 – Finance, p. 7.

336 Ofgem RIIO-2 – Finance, p. 7.

337 Ofgem RIIO-2 – Finance, pp. 26-30.

338 Ofgem RIIO-2 – Finance, p. 30. The 2018 framework decision proposed calibration in the following way: change in the cost of equity = $(1 - \beta)$ x change in risk-free rate. Ofgem,"RIIO-2 – Framework Decision", July 2018, p. 22.

339 Ofgem, "RIIO-2 Sector Specific Methodology Annex: Finance, December 2018 ("RIIO-2 – 2018 Finance Annex"), p. 71.

340 Ofgem, "RIIO-1 – Initial Proposals Overview", July 2012, pp. 35-36. The intention behind the "return on regulatory equity range" is that "companies should be able to achieve an upside return on (regulatory) equity (…) and be exposed to a downside return at or below the cost of debt."

341 Ofgem RIIO-2 – 2018 Finance Annex, p. 71.

342 Ofgem RIIO-2 – Finance, 113.

e. Treatment of tax and inflation

467. Companies receive a tax allowance that is separate from the determination of the authorised return. The previous price review, RIIO-1, also included a clawback mechanism on any tax benefits the regulated companies may have received due to higher than notional gearing, or changes in tax rates.[343]

468. For the current price review, Ofgem considers three options without having rendered a decision at this stage:

a. A notional tax allowance with clawback mechanism.

b. Pass-through of actual taxes paid.

c. The lower of allowance and actual taxes paid.[344]

469. Ofgem is investigating the reasons for deviations between allowed and paid taxes, which any future clawback mechanism would incorporate.[345] Ofgem is also considering whether to require regulated companies obtain the "Fair Tax Mark" (FTM) and whether it adds consumer value.[346]

470. As discussed above, Ofgem uses long-term inflation forecasts to convert from nominal to real values (see above).

f. Imputation tax credits

471. Not applicable

g. Other factors

472. As discussed above, Ofgem distinguishes between expected and authorised return. As a working assumption based on evidence from other price controls from both within and outside the energy sector, Ofgem proposes to deduct 0.5% points from its cost of equity for "expected outperformance".[347]

H. Ofwat

473. Ofwat is the regulatory body for the water and wastewater industry in England and Wales. It oversees 17 monopoly water companies whose business is to secure and treat water resources as well as distribute it through to retail.[348]

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343 Ofgem RIIO-2 – 2018 Finance Annex, p. 63. In addition to excess gearing, the clawback has a second condition whereby interest costs need to exceed assumed interest costs. See Ofgem, "RIIO-GD1: Initial Proposals, Supporting Document – Finance and Uncertainty", July 2012, p. 38.

344 Ofgem RIIO-2 – Finance, p. 103.

345 Ofgem, "RIIO-2 Framework Consultation", March 2018, p. 98.

346 Ofgem RIIO-2 – Finance, p. 105. The FTM is an accreditation UK companies may receive for transparent reporting and accounting.

347 Ofgem RIIO-2 – Finance, p. 77.

348 Ofwat, "PR19 Final Determinations – Policy Summary, December 2019, ("Ofwat PR19 – Policy Summary"), p. 4.

1. The regulatory framework

a. Objective

474. Ofwat's statutory duties require it to:

a. "further the consumer objective to protect the interests of consumers, wherever appropriate by promoting effective competition;

b. secure that water companies properly carry out their functions;

c. secure that the companies are able (in particular, by securing reasonable returns on their capital) to finance the proper carrying out of those functions [the "financeability duty"]; and

d. further the resilience objective to secure the long-term resilience of companies' systems and to secure that they take steps to enable them, in the long term, to meet the need for water supplies and wastewater services."[349]

475. While Ofwat has a financeability duty, it carries out its assessment with respect to a notional, i.e. efficient, company. The determination of the authorised return is unaffected by financeability considerations. However, Ofwat has mechanisms in place for companies to address financeability constraints.[350]

476. Ofwat's price review follows four phases stretching over several years. For its most recent price review, PR19, Ofwat started the development of the PR19 methodology in 2015 with consultations on changes to the regulatory framework. In the second phase, Ofwat assessed companies' business plans against its expectations and requirements. Ofwat published its draft determinations between April and July 2019.[351] Following further consultations and formal representations by companies, Ofwat published its final determinations in December 2019. Companies can appeal Ofwat's decisions and bring their case before the Competition and Markets Authority.

477. The price reviews set limits on the revenues regulated companies can charge, and regulates the service and incentive packages for companies. Ofwat considers regulatory periods of 5 years, with PR19 running from 2020-25. As part of the decision on revenue controls, Ofwat determines the authorised rate of return.

349 Ofwat PR19 – Policy Summary, pp. 18-19 and Water Industry Act 1991.

350 Ofwat PR19 – Policy Summary, pp. 59-60. For example, it is possible for companies to "advance revenues" by bringing forward cash flows from future periods. 12 out of the 17 regulated companies make use of this. For details, see Ofwat, "PR19 Final Determinations – Aligning Risk and Return Technical Appendix", pp. 67-99.

351 Depending on the business plan assessment, Ofwat considers a "fast track" for companies whose business plans are of "high quality" and draft determinations are published earlier and a "slow track" and "significant scrutiny status" for companies required to resubmit business plans. See Ofwat PR19 – Policy Summary, pp. 21-24.

b. Timing and sequencing

478. As discussed above, Ofwat considers regulatory periods of 5 years, with PR19 running from 2020-25. As part of the decision on revenue controls, Ofwat determines the authorised rate of return.

2. Rate of return

a. The overall rate of return

479. PR19 determines the authorised return companies on the regulated capital value (RCV). The RCV is indexed to inflation over the regulatory period, which requires calculating a (vanilla) WACC in real terms. As other regulators in the UK, Ofwat principally relies on the CAPM framework to calculate the cost of equity, and makes crosschecks based on alternative approaches. It calculates the cost of debt as a weighted average of new and old debt, both of which are based on benchmark indices. Ofwat makes company-specific adjustments to the cost of debt allowance for a selection of small companies. Table 18 summarises the parameters from Ofwat's PR19.

Table 18
Summary of Ofwat Authorised Return

Measure		Source	Estimate	Methodology
Allowed Return on Debt (pre-tax)	[1]	Technical Appendix p. 72	2.14%	Average of new and embedded debt based on bond indices
Risk-free Rate	[2]	Technical Appendix pp. 38-40	-1.39%	15-year RPI-linked government bonds plus implied rate rise
Market Risk Premium	[3]	[4]-[2]	7.89%	
Total Market Return	[4]	Technical Appendix p. 53	6.50%	Assumption based on multiple sources
Raw Beta	[5]	Technical Appendix p. 69	0.63	2 UK comparators, 2-5 year daily estimates
Comparator gearing	[6]	Technical Appendix p. 69	54.20%	Comparator gearing
Debt Beta	[7]	Technical Appendix p. 68	0.125	External studies
Asset Beta	[8]	[5]x(1-[6])+[7]x[6]	0.36	Unlevered beta using net debt to equity for comparators
Gearing	[9]	Technical Appendix p. 69	60%	Assumption
Notional Equity Beta	[10]	([8]-([7]x[9]))/(1-[9])	0.71	
Cost of Equity (post-tax)	[11]	[2]+[3]x[10]	4.19%	
Appointee Allowed Return on Capital (vanilla)	[12]	[1]x[9]+[11]x(1-[9])	2.96%	
Retail Margin Adjustment	[13]	Technical Appendix p. 16	0.04%	Adjustment for reduction in systematic risk
Wholesale Allowed Return on Capital (vanilla)	[14]	[12]-[13]	2.92%	

Notes and sources:
Expressed in CPIH-adjusted terms.
Ofwat, PR19 Final Determinations - Allowed Return on Capital Technical Appendix, 2019.
We assume a raw beta of 0.633 (Ofwat tables show only two decimals) in order to avoid rounding errors.

b. Cost of debt

480. Ofwat considers several elements in its determination of the debt allowance and calculates the cost of debt in part based the cost of new debt, and in part based on the cost of old debt.[352] The 80%:20% weighting is estimated by examining company forecasts. Ofwat calculates both the cost of new debt and old debt with reference to

352 Ofwat calculates the share of new debt at 20%. Ofwat – Technical Appendix, p. 73.

the iBoxx bond indices reflecting the cost of debt of A and BBB rated non-financial company indices with 10 years or more to maturity.[353]

a. The cost of new debt is estimated using the current rate with an upwards adjustment of 25bp to account for the expected increase in market rates over the regulatory period, and a downward adjustment of 15bp to account for the outperformance Ofwat believes an efficient company is expected to achieve.[354] Outperformance here refers to the observation that regulated companies issue debt at a lower rate relative to the benchmark. The cost of new debt is to be reconciled in the next regulatory period with outturn rates in the benchmark index.[355] More specifically, Ofwat will calculate the difference (positive or negative) between revenues companies obtain based on the PR19 allowance and revenues based on an allowance using outturn values for the index. This reconciliation will affect future revenues as part of PR24, the next regulatory period.[356]

b. The cost of old debt uses 15-year trailing averages and is also adjusted for outperformance. Ofwat considers the 15-year average to be a "more appropriate reflection of the sector's issuance profile", compared to a shorter average.[357] Ofwat crosschecks this value against actual company balance sheet data excluding "non-standard debt instruments".[358] It finds that its estimate of old debt is similar to the median cost for water and sewerage companies and large water only companies.[359]

481. Both elements of the debt allowance are deflated using Ofwat's inflation assumptions (see below). Ofwat adds an uplift of 10bp to account for issuance and liquidity fees based on an analysis of issuance costs by its external consultants.[360]

482. Ofwat also considers company-specific adjustments to the cost of debt subject to specific tests. The adjustment that companies may request are subject to assessments of the evidence put forward for the level of the adjustment, whether there are benefits to customers compensating for the increased cost, and whether there is customer support for any uplift. Four companies applied for an uplift and for two Ofwat finds that an uplift is justified after having passed the tests. The uplift applied

353 Ofwat uses an average A and BBB-rated iBoxx indices. Ofwat PR19 Draft Determinations, p. 74. A report by Europe Economics suggests that the average Ofwat uses is unweighted. See Europe Economics, "The Cost of Capital for the Water Sector at PR19", 17 July 2019, p. 46.

354 Ofwat PR19 – Technical Appendix, p. 78. The uplift is calculated with reference to the term structure of nominal gilts, and is intended to capture the increase in the cost of long-term debt to be issued over the regulatory period, implied by the current term structure.

355 Ofwat PR19 – Technical Appendix, p. 72.

356 Ofwat PR19 Draft Determinations, p. 65.

357 Ofwat PR19 – Technical Appendix, p. 90.

358 Ofwat excludes swaps, debt with equity-like characteristics, short-term credit facilities, callable debt. Ofwat PR19 Draft Determinations, pp. 72-74.

359 Ofwat PR19 – Technical Appendix, p. 90.

360 Ofwat PR19 – Technical Appendix, pp. 92-93.

is calculated by Ofwat, and does not exactly reflect company-specific differences in debt. The uplift is based on small-company premia.[361]

c. *Cost of equity*

483. A study by Wright et al commissioned by the UK Regulators Network (UKRN) made the specific recommendation to the sectoral regulators to calculate the WACC based on the CAPM methodology.[362] Ofwat follows this approach and makes additional crosschecks on its results using alternative approaches.[363]

484. Ofwat distinguishes between wholesale and retail controls.[364] An adjustment is needed to remove any systematic risk related to retail business which is compensated in the retail margin and therefore does not need to be compensated in the rate of return at the wholesale level (while the benchmark equity beta estimate includes both wholesale and retail systematic risk). Ofwat makes a downward adjustment to the authorised return of 0.04%.[365]

Equity beta

485. Ofwat follows four principal steps in obtaining its estimate of the equity beta. It measures the raw beta based on two listed UK water companies, averaging daily betas over 2 and 5 year periods up to the current date considered.[366,367] Second, it calculates the gearing of the two comparators with reference to 2 and 5 year averages of daily net debt over equity ratios. Rather than unlevering the beta with the corresponding gearing of each of the comparators, Ofwat works with averages of both beta and gearing. Third, Ofwat includes a debt beta from a study by Europe Economics, and Ofwat settled on a point estimate of 0.125 at the lower bound of the range considered. A non-zero debt beta has the effect of reducing the relevered equity beta by a small amount (because the notional gearing assumption is slightly greater than the comparator gearing). The fourth step consists of relevering the beta using Ofwat's notional gearing assumption of 60%.[368]

Market Risk Premium

486. Similar to Ofgem, Ofwat calculates the MRP based on a Total Market Return (TMR) methodology, which measures the MRP as the difference between the real TMR and the real risk free rate. The assumption underlying the TMR methodology is that

[361] Ofwat PR19 – Technical Appendix, pp. 94-102.
[362] Wright et al, p. 7.
[363] See, for example, Ofwat – Technical Appendix, pp. 26-28.
[364] Ofwat PR19 – Policy Summary, pp. 25-27.
[365] Ofwat PR19 – Technical Appendix, pp. 12-16.
[366] Ofwat considers both ordinary least squares (OLS) and generalised autoregressive conditional heteroscedasticity (GARCH) models in the estimation.
[367] There is a third listed UK water company, which Ofwat discards in its estimation "because a significant proportion of its revenues derive from activities outside of regulated water." See Ofwat PR19 – Technical Appendix, p. 54.
[368] Ofwat PR19 – Technical Appendix, pp. 62-69.

the expected total return to equity is relatively stable in real terms, and that the expected MRP adjusts over time to reflect changes in the real risk free rate.

487. Ofwat considers various approaches to, and estimates of, the TMR. It broadly assesses three approaches:

a. An ex-post approach based on historical UK equity returns, converted into real returns, considering different holding periods (5-10 years) and different averaging methodologies (arithmetic, geometric, weighted average of the two). Ofwat also considers a whole-period geometric average adjusted for different holding periods and with an uplift to convert to arithmetic returns. Ofwat finds comfort in the fact that the range of values it calculates exceeds one-year holding period arithmetic returns for Europe and the world.[369]

b. An ex-ante approach that Ofwat understands "aim[s] to separate historical return expectations from realised returns, using an estimate of the former to infer investors' current expectations for TMR."[370] Under this approach, Ofwat calculates the total market return based on a Fama & French dividend growth model, considering different averaging periods of 1900-2018 and 1990-2018. As an alternative ex-ante approach, Ofwat also refers to a study by Dimson, Marsh and Staunton (2019) whose method is similar to that of the ex-post approach but adjusts historical data for unrepeatable events.[371]

c. A forward-looking approach for which Ofwat commissioned external consultancies to calculate returns based on dividend discount models.[372] In its draft determinations, Ofwat also considered surveys from practitioners and evidence from market-to-asset ratios,[373] which do not enter its final determinations, however.[374]

488. Ofwat settles on a point estimate for the TMR of 6.5%, which it finds is within the ranges of each of the three approaches considered, as well as the range indicated by Wright et al and Ofwat's external consultants.[375]

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369 Ofwat PR19 – Technical Appendix, pp. 41-42. The study by Wright et al recommends calculating a geometric average TMR and adding an uplift to obtain an arithmetic average, which it argues is more appropriate than calculating arithmetic averages directly. See Wright et al, p. 125.

370 Ofwat PR19 – Technical Appendix, p. 42. Also see Ofwat, "PR19 Draft Determinations: Cost of Capital Technical Appendix", July 2019 ("Ofwat PR19 Draft Determinations"), p. 38.

371 Ofwat PR19 – Technical Appendix, p. 41.

372 Ofwat PR19 – Technical Appendix, pp. 51-52.

373 Market-to-asset (MAR) analysis attempts to "infer an investor cost of equity from the premium of the market valuation of regulatory equity over its face value", which is then converted to a TMR figure. See Ofwat PR19 Draft Determinations, pp. 41-42.

374 Ofwat PR19 – Technical Appendix, pp. 42-43 and 51.

375 Ofwat PR19 – Technical Appendix, p. 53.

Risk free rate

489. Ofwat considers a 15-year "investment horizon" and accordingly derives the risk-free rate from 15-year RPI-linked gilts. It takes the spot yield averaged over one month of -2.61%[376] to which it adds an average market-implied increase over 2020-25 of 0.26%.[377] The yield increase is a forward rate implied in the term structure of RPI-linked gilts.[378] Ofwat then adjusts the so obtained rate by the differential between the RPI and the CIPH of roughly 100bp to arrive at a real risk-free rate of -1.39% over the regulatory period.

d. Gearing

490. Ofwat assumes notional gearing of 60% in its determinations. It reduced gearing from 62.5% for the previous price review mainly because PR19 increased the share of revenues at risk from service performance.[379] Ofwat observes that actual company gearing is in excess of its notional gearing assumption but that it forecasts gearing to decrease over the regulatory period.[380]

e. Treatment of tax and inflation

491. Similarly to Ofgem, Ofwat has moved from the RPI to the Consumer Price Index including owner occupiers' housing costs (CPIH) as the preferred measure of inflation as the RPI is no longer considered a robust measure of inflation.[381] While the RPI is still published, it no longer has the designation as an official inflation statistic for technical reasons.[382] In order to transition away from the RPI and starting with the new regulatory period, Ofwat indexes 50% of each company's

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376 Ofwat uses the month of September 2019 for its final determinations published in December 2019. Ofwat PR19 – Technical Appendix, p. 38. The rationale for averaging over one month is to limit inter-day volatility while including most recent data.

377 Ofwat PR19 – Technical Appendix, p. 38. The rate rise is taken from Europe Economics, which has been advising Ofwat on various aspects of its return methodology.

378 For example, the rate rise on a 10-year gilt X years in the future can be measured with respect to the 10-year spot rate and a 10+X-year gilt, which implies a forward rate on a 10-year gilt. The headline market-implied rate increase is calculated as an average of rate increases for different Xs across the regulatory period. For more details, see Europe Economics, "The Cost of Capital for the Water Sector at PR19", 17 July 2019, pp. 23-25.

379 Ofwat PR19 – Technical Appendix, p. 11.

380 Ofwat PR-19 Draft Determinations, pp. 11-12. Moreover, Ofwat has a "gearing outperformance sharing mechanism" in place. Companies with gearing levels above certain trigger points (74% for the first year of PR19) have to make sharing payments based on a reference gearing level and a sharing rate. The "gearing outperformance" is to be reconciled with the next price review. For more details see Ofwat, "PR19 Final Determinations – Aligning Risk and Return Technical Appendix", pp. 125-131.

381 Ofwat, "PR19 Final Determinations – Allowed Return on Capital Technical Appendix ("Ofwat PR19 – Technical Appendix"), p. 8.

382 UK Statistics Authority, Assessment of Compliance with the Code of Practice for Official Statistics, The Retail Prices Index, Assessment Report 246, March 2013.

RCV to the RPI, and the other 50% to the CPIH, including RCV additions. This requires it to apply the authorised return separately for different tranches of the RCV.[383]

492. To convert between nominal and real values, Ofwat relies on the consensus of independent forecasters whose predictions for the CPIH range between 1.98% and 2.1% over the regulatory period. Based on the same data, Ofwat infers a RPI-CPIH wedge between 0.89% and 1.1%.[384] Ofwat intends to reconcile any differences between assumed and outturn RPI-CPIH wedge in PR24, the next regulatory period.[385]

493. Ofwat includes an allowance for corporate taxes as part of the revenue allowance. It calculates the tax allowance for each individual company based on project taxable profits. Ofwat includes a reconciliation mechanism to account for changes in the tax rate, depreciation allowance, changes in the cost of debt (see corresponding section above), and tax credits arising at the group level.[386]

f. Imputation tax credits

494. Not applicable

g. Other factors

495. As discussed above, Ofwat adds an uplift of 10bp to the cost of debt to account for issuance and liquidity fees based on an analysis of issuance costs by its external consultants.[387] Ofwat also considers company-specific adjustments to the cost of debt subject to specific tests.

383 Ofwat – Technical Appendix, p. 8.
384 Ofwat PR19 – Technical Appendix, pp. 8-10.
385 Ofwat PR19 – Technical Appendix, p. 8.
386 Ofwat, "PR19 Final Determinations – Aligning Risk and Return Technical Appendix", pp. 107-110.
387 Ofwat PR19 – Technical Appendix, pp. 92-93.