Decision

RIIO-3 Final Determinations – Finance Annex

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The next set of price controls for the Electricity Transmission (ET), Gas Distribution (GD) and Gas Transmission (GT) sectors will cover the five-year period from 1 April 2026 to 31 March 2031 (RIIO-3). In December 2024, the network companies in these sectors submitted their RIIO-3 Business Plans for this period to Ofgem. We assessed these plans and published our Draft Determinations for consultation on 1 July 2025. Following consideration of consultation responses, this document and others published alongside it set out our Final Determinations for the RIIO-3 price controls.

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1. Introduction

Purpose of this document

1.1 This document sets out our Final Determinations positions on the financial framework for the price control for the GD, GT and ET network companies in Great Britain (GB), covering the five-year period from 1 April 2026 to 31 March 2031 (RIIO-3). All figures in this document are in 2023/24 prices, except where otherwise stated.

What is the financial framework?

1.2 Our price controls set revenues that network companies are allowed to recover from consumers. These allowed revenues are based on the costs that they incur for developing and operating gas and electricity networks. Ultimately, consumers pay for these allowed revenues through their bills.

1.3 Network companies incur financing costs in maintaining and upgrading the network to ensure safe and reliable energy supplies to consumers. To ensure financing costs are efficient and fair, our financial framework sets allowances for network companies on a notional basis; but are expected to make commercial decisions on how to best finance their operations. Our framework compensates them for being financed efficiently and sustainably while delivering value for consumers. This, in turn, promotes stability for the network companies, investors and consumers.

1.4 Our financial framework is well established and designed to be transparent, stable and predictable. This helps attract continued investment into the sector and set fair returns for network companies and investors which, in turn, lowers costs for consumers. In RIIO-3, it will be vital for network companies to attract investment to maintain secure and resilient networks, while supporting the delivery of the clean power energy transition and connecting new sources of demand. Setting clear and objective financial parameters in our framework plays a key role in maintaining sector investment.

1.5 Our financial parameters also incentivise network companies by offering higher, or lower, returns based on their performance and the delivery of their targets for consumers. Our framework also has mechanisms in place to safeguard consumers and investors alike from excessive returns or losses.

What are we deciding?

1.6 The scale of investment that will be required in RIIO-3 is unprecedented, with the gas and electricity sectors both facing pivotal moments. As the demand for

electricity grows, particularly for AI, electrified transport, and advanced manufacturing, it will be increasingly important to ensure our transmission system can balance supply and demand in a more flexible way. While the future of the gas networks is less certain, transmission and distribution networks continue to have a vital role in ensuring consumers receive a safe and resilient supply while we transition to alternatives. Although this investment will deliver significant benefits over generations, the associated costs, paid for by consumers through their energy bills, need to be carefully balanced in the RIIO-3 period and beyond. These challenges accentuate the need for network companies to raise and service capital competitively and at an efficient cost to consumers.

1.7 The sectoral challenges and the global context, including the rise in interest rates since RIIO-2, mean that our financial parameters have evolved. Our starting point is to maintain similar foundational allowances to RIIO-2, while adjusting our methodologies in certain key areas. This means our financial framework remains predictable and stable, while also adapting to the global financial environment and the changing needs of consumers. In setting our financial framework, we have considered evidence submitted by stakeholders and present in this document our decisions along with analysis and rationale.

Returns

1.8 Our returns parameters are calibrated so that they are competitive and can attract the investment needed for RIIO-3 while being fair to consumers.

1.9 Our cost of debt allowance includes targeted methodology changes set out in Chapter 2. For example, we are implementing a nominal allowance for fixed rate debt to protect consumers from inflation shocks (with our RAV indexation decision set out in Chapter 11); a change in benchmark indices for calibrating debt costs; and updates to specific allowances to better reflect the efficient debt costs for gas and electricity networks, on a notional basis, in the RIIO-3 period.

1.10 Chapter 3 sets out our methodology for determining return on equity allowances and confirms our assumptions for dividend yield and equity issuance costs. It explains how we apply the Capital Asset Pricing Model (CAPM) framework to calculate the cost of equity and the cross-checks we perform to ensure these allowances are appropriately balanced - neither excessive nor insufficient. This rigorous process underpins the investability of the overall financial package. We have decided on allowances of 5.70% at 55% gearing and 6.12% at 60% gearing.

1.11 We have summarised our overall Weighted Average Cost of Capital (WACC) for each sector in Chapter 4, using data as at October 2025 and combining the allowances for equity, index-linked debt and fixed rate debt. We have assumed 55% notional gearing for ET and 60% for the gas sectors and set out our decision to not maintain a "flat WACC" approach across the sectors. Our WACC allowances are 5.62% (unweighted average) for ET (55% gearing) and 5.24% for gas (60% gearing).

1.12 Chapter 9 covers our approach to setting our return adjustment mechanisms (RAMs). Our approach is broadly unchanged from RIIO-2, but will include major projects in our existing mechanisms for RIIO-3.

Asset lives and revenues

1.13 Energy infrastructure is used over the course of many decades. Our financial framework ensures that consumers do not pay for all of these costs today and that network revenues are spread out proportionately, supporting intergenerational fairness and network cash flows. Our starting point is to assume that the costs of assets are paid back over their economic lives and make adjustments where necessary. Our adjustments below are targeted so that we carefully balance revenues against risks.

1.14 Chapter 5 covers our financeability assessment and whether, when all elements of our Final Determinations are considered together, an efficient operator adopting the notional capital structure would be able to generate sufficient cashflows to meet its debt financing obligations. In ET we have decided to adopt an 85% bucket 2 capitalisation rate, to underpin the significant growth in capital expenditure.

1.15 Chapter 8 covers our approach to setting depreciation for RIIO-3. In line with our Draft Determinations, we are accelerating depreciation for GD assets added to the regulatory asset value (RAV) during RIIO-3. We will leave the depreciation profile unchanged for ET and GT.

1.16 Chapter 10 sets out revenue profiling measures that we have introduced at Final Determinations (with further detail set out in our Impact Assessment. Recognising the step change in allowed revenues between RIIO-2 and RIIO-3 and the impact that is expected to have on the non-domestic supply market, consumers and businesses, we are profiling allowed revenues from earlier years in RIIO-3 to later years within the period. We will include further details in our licence drafting statutory consultation that will be published later this month.

Other aspects

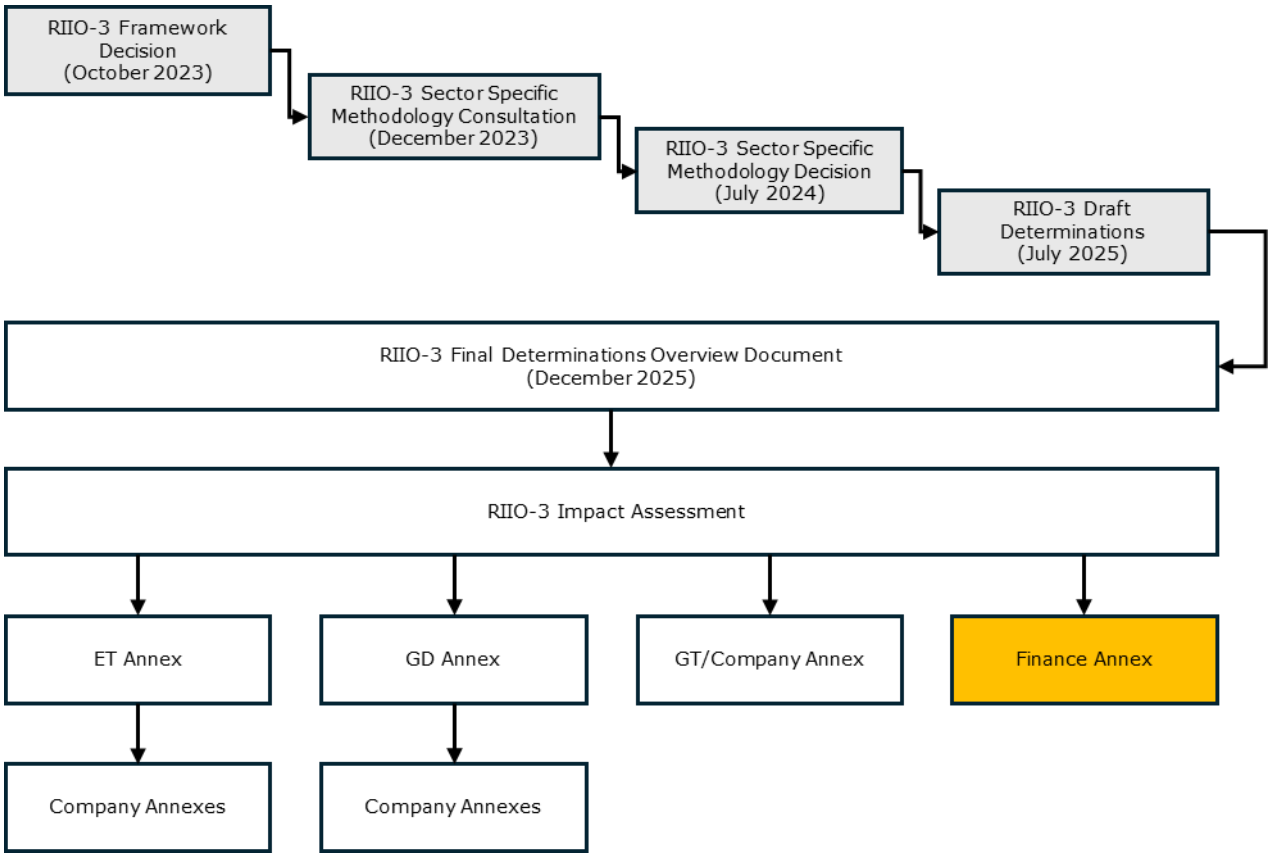
1.17 We are also implementing new measures to promote financial resilience which are set out in Chapter 6. The aim of these measures is to further increase confidence in the energy sector and help ensure it is set up to protect consumers from any significant deterioration in resilience, whilst imposing no additional costs on network companies operating with responsible financing strategies.

1.18 Chapter 7 sets out our approach to setting Corporation Tax allowances. We consulted on updates to the definitions of Adjusted Net Debt and Tax Deductible Net Interest within the Tax Clawback and are making amendments. In our Draft Determinations, we also consulted on whether a tax forecasting penalty was needed in RIIO-3 and have decided that it is not required.

1.19 Finally, we summarise our decisions on other financial issues in Chapter 12.

Navigating the RIIO-3 Final Determinations documents

Figure 1: RIIO-3 Final Determinations map



1.20 The RIIO-3 Final Determinations are comprised of an Overview Document, a Finance Annex and sector annexes for ET, GD and GT. This document is the Finance Annex. The sector annexes are underpinned by a RIIO-3 Impact Assessment, company annexes and, where relevant, technical annexes. Figure 1

above maps all documents relevant to our suite of RIIO-3 Final Determinations, including the framework and methodology documents that have preceded it.

2. Allowed return on debt

Purpose: Providing a reasonable allowance for debt costs that updates with changes in market conditions.

Benefits: Providing an allowance that references an appropriate index that incentivises networks to minimise their debt costs, which over time feeds through into lower costs for consumers. Adjusting for market rate movements protects both consumers and networks from ex ante forecast error.

Final Determinations summary

Parameter	Final Determination	Draft Determination
Benchmark index selection	To index the cost of debt allowance with reference to the simple average of the iBoxx GBP A (ISIN reference: DE000A0JY837) and iBoxx BBB (ISIN reference: DE000A0JZAH1) non-Financials 10+ corporate indices.	Same as FD.
Notional Index-Linked Debt (ILD) assumption	ET: 10% ILD assumption (90% of the ET allowed return on debt would be provided in nominal terms and 10% in real terms). Gas: 30% ILD assumption (70% of the gas allowed return on debt would be provided in nominal terms and 30% in real terms).	Same as FD.
Deflation of ILD assumed portion to CPIH (Consumer Price Index including owner occupied housing costs)	For ILD assumed portion utilise the 5-year Office for Budget Responsibility (OBR) forecast for CPI to deflate the nominal "all in" yields available for each date of the trailing average to CPIH real yields, using the Fisher equation. Going forward from the initial publication of the OBR forecast of CPIH we will utilise the 5-year OBR forecast for CPIH to deflate the nominal "all in" yields	For ILD assumed portion utilise the Bank of England CPI inflation target (2%) as a proxy for long run CPIH to deflate nominal "all in" yields for each date of the trailing average to CPIH real yields using the Fisher equation.

Parameter	Final Determination	Draft Determination
	using the methodology stated above.	
Additional cost of borrowing	ET: to add 0.26% to the index above for additional borrowing costs. Gas: To add 0.32% to the index above for additional borrowing costs.	ET: to add 0.19% to the index above for additional borrowing costs. Gas: To add 0.25% to the index above for additional borrowing costs.
Infrequent issuer premium	No separate allowance proposed for RIIO-3.	Same as FD
Calibrating the index - weighting	ET: RAV weighting of the benchmark index beginning from the start of RIIO-1. Gas: Simple average of the benchmark index.	Same as FD
Calibrating the index - trailing average length	To calculate the allowance using a 14-year trailing average.	Same as FD
Calibrating the index - calibration adjustment	ET: To include a fixed upwards adjustment of 0.39% to the trailing average, excluding additional costs of borrowing. Gas: To include a fixed upwards adjustment of 0.72% to the trailing average, excluding additional costs of borrowing.	ET: To include a fixed upwards adjustment of 0.45% to the trailing average, excluding additional costs of borrowing. Gas: To include a fixed upwards adjustment of 0.60% to the trailing average, excluding additional costs of borrowing.
Calibration of allowed return on debt - exceptional cases	To include a close out mechanism to consider costs related to the transition of Retail Price Index (RPI) to the CPIH methodology from 2030.	Same as FD

2.1 In this section, we set out our decision for setting the cost of debt allowance and address the related issues raised in the response to our Draft Determinations. The cost of debt allowance is an estimation of the return debt investors expect from an efficiently run company. The allowance considers embedded debt raised prior to the RIIO-3 price control period and new debt to be raised in the current price control period.

2.2 Our intention is to provide a reasonable allowance for debt costs which updates with changes in the market conditions, based on an appropriate index. Consistent with our position in Draft Determinations, we have decided to continue with full indexation of the allowed return on debt.

2.3 We allow additional costs of borrowing within our final allowance, reflecting those costs that we expect to be efficiently incurred by the notional entity.

2.4 We continue to set the allowed return on debt in line with the UK Regulators Network (UKRN) Guidance[1] and choose to exclude most derivatives.

2.5 The following table represent forecast Final Determinations of the cost of debt allowances.

Table 1: Forecast cost of debt allowance (semi-nominal)

Sector	Y2027	Y2028	Y2029	Y2030	Y2031	Average
GD&GT	4.45%	4.55%	4.64%	4.77%	4.91%	4.66%
NGET	4.90%	5.08%	5.32%	5.55%	5.72%	5.31%
SHET	5.20%	5.58%	5.87%	6.05%	6.15%	5.76%
SPT	5.14%	5.39%	5.61%	5.81%	5.96%	5.58%

2.6 For the gas sectors the allowed return on debt is derived from a 14-year simple average of the average iBoxx GBP A and BBB non-financial 10+ index, plus calibration adjustment of 72bps, plus 32bps of additional costs of borrowing.

2.7 For the ET sector the allowed return on debt is derived from a 14-year RAV weighted trailing average of the average iBoxx GBP a and BBB non-financial 10+ index, plus 39bps calibration adjustment, plus 26bps of additional costs of borrowing.

2.8 In RIIO-3, the allowed return on debt will be set on a semi-nominal basis, with the allocation between nominal and real components determined by the notional assumptions for fixed-rate and index-linked debt. For ET, we applied a notional index-linked debt assumption of 10%, meaning that 90% of the debt allowance will be provided on a nominal basis and 10% on a real basis. For gas we have applied a notional index-linked debt assumption of 30%, meaning that 70% of the debt allowance will be provided on a nominal basis and 30% on a real basis. To avoid overcompensation under this partially nominal approach, RAV indexation is adjusted accordingly. The approach to RAV indexation is discussed in Chapter 1.

[1] UKRN cost of capital guidance

Estimating efficient debt costs and calibrating the index

2.9 The calibration of the allowed return on debt is intended to broadly align forecast average efficient debt costs over RIIO-3. The allowance is set with reference to a trailing average of an index of public debt instruments to enable the allowance to respond dynamically to changes in the market interest rate environment.

2.10 In our SSMD and Draft Determinations, we proposed introducing a RAV-weighted trailing average for all ET networks but retaining the RIIO-2 unweighted approach for gas networks. For ET, we proposed adopting the RAV weighting for the trailing average owing to the high level of expected RAV growth, and consequent new debt issuance over RIIO-3, which will generate greater exposure to the current higher interest rate environment than GD & GT will face.

2.11 We also said we would continue, as in RIIO-2, to conduct a calibration approach that considers forecast average efficient debt costs. However, unlike in RIIO-2, we have conducted separate assessments of gas networks and ET networks reflecting empirical divergences that have emerged between the two sectors.

2.12 As set out in our SSMD, we undertook a review of the methodology for calculating the forward rate, used to determine the rate at which new debt will be financed each year. Following this review in the Draft Determinations, we proposed that the forecast nominal annual yield be calculated as the average of the relevant iBoxx outturn data from the most recent full calendar month available at the time of the update.

2.13 In our SSMD, we decided to exclude the following instruments from consideration in the calibration exercise:

- Derivative instruments - as we consider the allowance can reasonably be achieved using standard debt instruments, and that derivative use is likely to reflect company-specific risk management decisions, and we therefore consider that the costs and benefits from these instruments should be borne by equity investors
- Liquidity facilities, revolving credit facilities and overdrafts - as these are considered in the additional costs of borrowing
- Intercompany loans other than back-to-back arrangements - as these may not represent commercial terms/pricing available from third parties
- Subordinated instruments, such as 'Class B' debt - not a standard funding instrument for core operations; it ranks below senior debt in the capital

structure, carries higher risk, and therefore typically demands interest rates above the cost of debt we aim to calibrate

- Instruments with insufficient data to model

2.14 For new debt, in our Draft Determinations we proposed a benchmark adjustment for gas of 25bps to the average of the iBoxx A and iBoxx BBB non-financial 10+ corporate index. We did not recommend a benchmark adjustment for ET.

2.15 In our Draft Determinations, we tested the suitability of calibrating the cost of debt index to different trailing average periods with forecast efficient industry debt costs under different scenarios; these scenarios involve varying assumptions in relation to expected totex and interest rates ie iBoxx and SONIA, over RIIO-3.

2.16 For gas, we recommended a 14-year simple trailing average with a 60bps calibration adjustment. The modelling indicated that this approach resulted in an allowance that remained broadly aligned with forecast average efficient costs under plausible sensitivity scenarios, providing confidence that consumer costs will remain fair and reasonable.

2.17 For ET, we recommended a RAV weighted 14-year trailing average with a 45bps calibration adjustment for ET. We recommended starting the RAV weighting from the start of RIIO-ET1 with an assumed refinancing period aligned to the trailing average assumption. We chose to include ED (assuming similar RAV growth to ET following the conclusion of RIIO-ED2) within the calibration group to mitigate the risk that an ET calibration cohort would be small (3 TOs) and dominated by the largest ET company.

Final Determinations decision

2.18 We have decided to maintain our approach of separately assessing gas networks and ET networks, reflecting empirical divergences that have emerged between the two sectors. We will also continue to utilise a RAV-weighted trailing average for all ET networks whilst retaining the RIIO-2 unweighted approach for gas networks within the general calibration exercise.

2.19 In the Final Determinations, we retained the inclusion of ED in the ET cost of debt calibration, to mitigate the risk that an ET calibration cohort would be small (3 TOs) and dominated by the largest ET company. Unlike in our Draft Determinations, which assumed similar ED RAV growth to ET after RIIO-ED2, we applied an ED RAV growth rate of 7%, based on assumed annual totex growth compared to RIIO-ED2. We consider this approach is more representative of expected network investment requirements.

2.20 We previously removed the timing lag between the October cost of debt setting and the March start of the regulatory period for ET companies and have now applied the same approach for the gas networks. We consider this helps bridge the gap between decision and implementation, slightly improving the accuracy of the cost of debt estimate.

2.21 We maintain our approach of using the one-month average iBoxx yield in the forecasting future interest costs and the 14-month trailing average. Our analysis at Final Determinations continues to support our position in our Draft Determinations that the 14-month trailing average strikes a reasonable balance between responsiveness and stability.

2.22 We have reviewed NERA's analysis on the gas premium and have updated the pricing date information and included five additional new issuances with new debt information we have received in our analysis. We have also excluded tenors of 10 years or less in order to more appropriately match the average tenor of the iBoxx indices. These adjustments have led to an increase in the new debt gas premium to 30bps, which is also supported when using a weighted average approach.

2.23 For the Final Determinations we tested the suitability of calibrating the cost of debt index using the 14-year trailing average period with forecast efficient industry debt costs under different scenarios; these scenarios involve varying assumptions in relation to expected totex and interest rates, over RIIO-3. The analysis in Table 2: Difference between expected industry debt costs and expected allowed debt costs, RIIO-3 average excluding derivativesillustrates the results of these scenario tests.

Table 2: Difference between expected industry debt costs and expected allowed debt costs, RIIO-3 average excluding derivatives

Sector	Index calibration	Base	Higher Totex	Lower Totex	Rates +1%	Rates -1%
GD & GT	14 Year TA + 72 bps	0.01%	0.00%	0.03%	0.00%	0.03%
ET Only	14 Year RAV weighted + 39 bps costs	0.34%	0.34%	0.35%	0.27%	0.42%
ET & ED	14 Year RAV weighted + 39 bps costs	0.07%	0.06%	0.07%	0.00%	0.15%
ET & ED	14 Year TA + 39 bps	-0.52%	-0.56%	-0.50%	-0.73%	-0.32%

2.24 We reaffirm our position on adjusting the assumed debt costs for the calibration cohort to reflect the Cadent refinancing. This approach is consistent with the methodology applied in our RIIO-2 Final Determinations.[2]

2.25 Our decision and rationale for the transition to semi-nominal rate are provided in the 'Treatment of inflation' section of this Chapter.

Stakeholder responses and our rationale

Responses to FQ1: Do you agree with our approach to estimating efficient debt costs and calibrating the index?

General responses

2.26 A private individual submitted a response contending that we have significantly overestimated the cost of debt for all companies under RIIO-3. The submission highlighted concerns about errors within our cost benchmarking methodology.

2.27 The private individual did not provide any supporting evidence for their claim in their response. We remain confident that our cost of debt estimate is appropriate, as it is grounded in regulatory precedent established during previous RIIO periods and policies, and supported by analysis and methodologies that have undergone extensive consultation.

2.28 Wales and West Utilities' (WWU) responses to our Draft Determinations on the cost of debt responses are provided subject to the legal notice in its full submission.[3] WWU is currently pursuing a judicial review concerning key financial issues from the RIIO-2 appeal. While these responses do not restate the legal case, they have been submitted without prejudice to the ongoing proceedings and should be read in that context. In summary, WWU says that its position, related to the cost of debt allowance, is that our rationale for rejecting point-in-time testing for debt efficiency is unconvincing.

2.29 The main calibration of the cost of debt is intended to broadly align forecast average efficient debt costs of the notional company over RIIO-3, ensuring companies are incentivised to manage their capital structure efficiently over the long term. Pricing at issuance is influenced by many factors, as noted in our Draft Determinations.[4] While point in time efficiency tests can be useful as a diagnostic tool when instruments appear significantly out of line with benchmarks, they are not robust or proportionate for setting an allowance based on long-term

[2] RIIO-2 Final Determinations – Finance Annex, paragraph 2.38
[3] RIIO-3 Draft Determination Response Document , page 133
[4] RIIO-3 Draft Determinations - Finance Annex, paragraph 2.136

efficiency. By contrast, for the gas new debt adjustment in RIIO-3, point-in-time testing was appropriate because the adjustment relates specifically to the cost of new debt issued within a defined period, using recent market data.

2.30 The majority of respondents continue to support the full indexation approach to setting the cost of debt allowance. Most also endorsed the separation of calibration cohorts between gas and electricity, the use of RAV-weighting for electricity transmission from the start of RIIO-1, and the semi-nominal approach.

Responses regarding trailing average selection

2.31 Cadent highlighted that a large calibration adjustment suggests the selected trailing average tenor or index does not align well with sector debt costs. It argues that a 'better fitting' trailing average would reduce volatility in scenario modelling and mitigate this risk. It contends that our own modelling shows that a 10-year trailing average more closely matches sector debt costs, resulting in lower calibration and less volatility. It also supports aligning the trailing average with typical sector debt issuance tenors.

2.32 Our modelling continues to indicate that a 14-year trailing average provides more consistent performance against forecast average costs in each given year, helping to reduce the risk of over or under funding during the price control period. The tables presented in our Draft Determinations show only averages, not single year comparisons for each trailing average. Our analysis shows that shorter trailing averages are more responsive, but both short and long averages exhibit greater year-on-year variation when aligned to forecast efficient costs, as illustrated in Table 3: GD&GT - Difference between the simple trailing average options pre-calibration adjustment and forecast efficient costs. A positive (negative) value indicates an allowance higher (lower) than forecast efficient costs. shows that the Calibration is influenced not just by index or averaging choices, but also by embedded debt figures and assumptions around new debt issuance, including expected quantum and interest rates. These factors are all reflected in our main calibration to ensure a balanced and comprehensive approach.

Table 3: GD&GT - Difference between the simple trailing average options pre-calibration adjustment and forecast efficient costs. A positive (negative) value indicates an allowance higher (lower) than forecast efficient costs.

Index calibration	**Y2027**	**Y2028**	**Y2029**	**Y2030**	**Y2031**	**RIIO-3 average**
10yr	-0.82%	-0.67%	-0.48%	-0.31%	-0.08%	-0.47%
14yr	-0.70%	-0.72%	-0.73%	-0.70%	-0.66%	-0.71%

Index calibration	Y2027	Y2028	Y2029	Y2030	Y2031	RIIO-3 average
15yr	-0.63%	-0.70%	-0.71%	-0.72%	-0.69%	-0.69%
17yr	-0.43%	-0.56%	-0.64%	-0.69%	-0.70%	-0.61%
18yr	-0.26%	-0.46%	-0.58%	-0.65%	-0.70%	-0.53%
20yr	-0.13%	-0.23%	-0.35%	-0.51%	-0.61%	-0.37%

Responses regarding cohort selections

2.33 SGN and Cadent support our decision to remove ET companies from the gas cohort, with SGN also supporting the retention of the Cadent adjustment. Both companies note the inclusion of National Gas in the cohort as a potential concern. SGN argues that reduced uncertainty about Nation Gas' future role in the gas sector lowers its risk profile, which in turn decreases the sector's average cost of debt. Similarly, Cadent highlights a growing misalignment with other GDNs, pointing to differences in regulatory depreciation as a key factor. SGN further notes that, with ET companies excluded, Cadent now represents a significant portion of the gas sector debt pool and is effectively setting the benchmark for the 'efficient' sector average. It also suggests that Cadent's strong credit rating, supported by its low-cost refinanced debt portfolio, may be influencing this outcome, and therefore proposes that the current debt-weighted benchmarking approach be reconsidered. SGN proposes that applying a simple average across the four GDNs, allocating 25% weight to each company, would provide a more robust approach.

2.34 We have not seen evidence to suggest that including National Gas in the cohort distorts the sector's average cost of debt to justify its exclusion. Regarding the impact of Cadent's debt profile, we continue to apply the same adjustment used in RIIO-2 to mitigate the impacts of Cadent's low-cost refinancing. Cadent maintains a broadly similar credit rating to other GDNs and was downgraded by S&P to BBB, from BBB+, in August 2024. This downgrade resulted from higher interest costs following the refinancing of a large portion of its debt at notably higher rates. Aside from the 2016 refinancing, we do not consider Cadent's cost of debt to differ materially from the rest of the sector.

2.35 Northern Powergrid (NPg) and another network company are also supportive of including ED companies in the ET calibration, however, NPg acknowledges the additional headroom this provides to ET companies and believes this "aiming up" should be considered in the cost of equity and extended to the gas networks. NPg does not support using ET companies in cross-checks or calibrations for the ED companies' cost of debt allowance.

2.36 Northern Gas Networks (NGN) and National Gas also note the headroom afforded to the ET companies through the inclusion of the ED comparators in the calibration. National Gas further comments that the headroom provided to ET companies does not reflect equal treatment across sectors and should be reconsidered in reaching our final decision on the inclusion of ED comparators. It argues that this places the gas sector at greater risk of under-recovering efficient debt cost, an exposure less evident in the ET sector, and is inconsistent with evolving market conditions recognised by us.

2.37 Cadent also references to the ET headroom linking it to an index outperformance.

2.38 We included ED networks in the ET cost of debt allowance, as above, to mitigate the risk of the ET cohort being too small and being dominated by one large ET network company. Most network companies agreed with this approach and have not provided any compelling evidence that we should not have included ED networks in the main calibration. We acknowledge that this results in headroom for the ET cost of debt allowance compared to what would apply if ET were calibrated in isolation (see Table 2: Difference between expected industry debt costs and expected allowed debt costs, RIIO-3 average excluding derivatives). We also note that the gas new debt adjustment of 30bps incorporates a 11bps, on average, headroom within the gas network's cost of debt calibration (ie. without the new debt adjustment, the cost of debt calibration adjustment would be 11bps lower on average).

Responses regarding gas new debt adjustment

2.39 NERA provided analysis on the gas premium applied to new debt.[5] It recommends a gas network premium of 45bps, which it contends reflects a gas network specific premium and a new issuance premium, compared to the 25bpss proposed in our Draft Determinations. Its rationale is primarily based on using the spread over gilts, rather than the yield, and aligning each issuance's tenor with the corresponding gilt yield. Its analysis draws on a sample of 23 bonds. It has contended that failing to control for tenor limits companies' ability to optimise their tenor selection. In addition, it analysed two pairs of gas and electricity bonds to illustrate a gas premium relative to electricity.

2.40 Cadent, referencing the NERA report mentioned above was also supportive of the gas premium assessment using relative spread to control for tenor and the relevant index selection.

[5] Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3

2.41 We do not agree with NERA's assertion that our approach restricts companies from issuing debt at specific maturities. Historical issuances demonstrate that companies have issued debt across a wide range of tenors, indicating they are not practically constrained by a sample tenor. The use of a sample is a proxy for market rates, not a directive on tenor. Companies retain the flexibility to issue debt at tenors that best suit their financing needs, provided the terms are efficient and aligned with market conditions. While spreads can offer more refined control for tenor differences to yields, they do not fully eliminate idiosyncratic factors that may influence individual debt pricing. Therefore, much like NERA suggest excluded certain tenors from its analysis to improve comparability, [6] it follows that excluding certain spreads may also be necessary to accurately assess what constitutes a representative gas premium. We have not seen the details for the 23 issuances used in NERA's spread analysis and therefore cannot comment on their suitability. Pertaining to NERA's final observation, we do not consider that a point-in-time sample of two pairs of gas and electricity bonds provides a reliable or representative measure of a gas premium.

2.42 Specifically in relation to our approach, NERA updated the pricing dates for three issuances and argued that the gas premium would be better illustrated if tenors of 10 years or less were excluded, to better align with the average tenor of the iBoxx A and BBB index.

2.43 We acknowledge NERA's response regarding our calculation of the gas premium and have updated our assessment.

2.44 A consumer group responded that the adjustment to the benchmark has been applied inconsistently compared to RIIO-2 and is greater than the evidence suggests. It also highlighted that the gas premium, according to our assessment, reflects a 18bps on a simple average basis, when weighted by issuance size, rather than the 25bps proposed in our Draft Determinations. Additionally, it argued that although we found evidence of a positive halo effect in ED2, no downward adjustment was made, with us explaining that the continuation of the halo effect for new debt was uncertain and its likely impact minimal. It considers that the same rationale should now be applied to the negative halo effect.

2.45 The consumer group did not provide any supporting evidence for its response. As outlined in our RIIO-2 Final Determinations[7], using the appropriate pricing dates and incorporating five additional new issuances, we observe an issuance premium

[6] Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3, p. 9
[7] RIIO-2 Final Determinations – Finance Annex, paragraph 2.23

of 30bps, even when weighted by issuance size. We expect this premium to persist throughout the RIIO-3 period.

Responses regarding forecasting future debt costs

2.46 Among those respondents who commented on the approach of using the one-month average iBoxx yield and holding it constant to forecast future interest costs, the majority expressed opposition. Their concerns included the inconsistency of this method with our historic approach and with the use of forward curves elsewhere in RIIO-3. Respondents also noted that the flat approach is highly sensitive to market interest rates in the cut-off month and may underestimate market expectations of interest rates over the price control period.

2.47 As we have noted prior to our Draft Determinations, the forward gilt curve introduces a term risk premium, which can overstate expected future interest costs. The use of a one-month average iBoxx yield remains a simple and transparent forecasting tool that reflects recent market conditions. Nevertheless, under the full indexing model, the choice of forecasting method has limited long-term impact because of the annual reset mechanism, which helps mitigate forecasting errors. Our calibration approach is designed to reflect actual market conditions rather than rely on perfect forecasts. If significant volatility were to impact the reliability of the one-month forecasts, alternatives approaches would be considered.

Responses regarding index downside scenarios

2.48 Many respondents suggested that a downside scenario of 1% does not sufficiently capture the volatility of interest rate risk over the RIIO-3 period. Some referenced a NERA report, noting that actual outturn iBoxx rates during RIIO-2 were 2.5% higher than forecasted, and therefore argued that an interest rate sensitivity of more than 2% would be more appropriate for calibrating the cost of debt headroom.

2.49 While we acknowledge the concerns raised regarding interest rate sensitivity, we do not consider the RIIO-2 outturn to be a directly comparable reference point. The RIIO-2 period included the COVID-19 pandemic, which introduced exceptional market volatility and distortions not expected in RIIO-3. As such, using RIIO-2 outcomes to calibrate RIIO-3 headroom may overstate the underlying interest rate risk.

Use of benchmark indices

2.50 In our Draft Determinations we proposed a switch to the average of the iBoxx GBP A and iBoxx BBB non-financial 10+ corporate indices as the benchmark index, for both gas and electricity, that was used previously in RIIO-1. We considered that this index choice was a suitable proxy for macro-changes in network debt costs and a broad representative index.

2.51 We noted that the iBoxx Utilities 10+, used in RIIO-2, had been impacted by sectoral and issuer specific events in the Water sector. We considered the current volatility inherent in the iBoxx Utilities, driven by causal factors largely distinct from the electricity and gas sectors, increased the risk that the index performance, and thus the allowance, could become misaligned to efficient energy network company cost.

Final Determinations decision

2.52 We have decided to continue to consider the use of the average of the iBoxx GBP A and iBoxx BBB non-financial 10+ corporate indices as the benchmark for both gas and electricity to be the most appropriate approach for RIIO-3.

2.53 Network companies have argued that the indices were influenced by sectors unrelated to the energy networks, result in a credit rating slightly higher than the notional company, water sector yields have limited impact on overall trends when viewed over a long-term trailing average, and the Utilities index offers a closer alignment with sector debt costs, requiring only a minor calibration adjustment. We do not agree and consider that a calibration adjustment remains necessary regardless of its size and incorporating sectors beyond UK energy networks provides a more diversified benchmark, reducing reliance on the volatility of any single sector. Furthermore, our chosen indices are consistent with the notional company's target rating of Baa1/BBB+, and we note that water sector volatility could continue to affect outcomes later in the price control period under full indexation if the Utilities index were retained.

Stakeholder responses and our rationale

Responses to FQ2: Do you agree with our proposal to use a combination of iBoxx GBP A and BBB 10+ non-financial indices rather than the iBoxx GBP Utilities 10+?

2.54 Most respondents expressed no objections to reverting to the use of the average of the iBoxx GBP A and iBoxx BBB non-financial 10+ corporate indices as the benchmark. Many emphasised that the calibration exercise was more critical than the choice of index itself, noting that each index has its own strengths and limitations.

2.55 Respondents noted that the non-financial indices were influenced by sectors unrelated to the energy network sector but noted that as being both a strength and a weakness. Respondents explained that while this influence reduced relevance to the sector, it also helped mitigate sector-specific volatility, particularly that associated with the UK water industry.

2.56 Three gas companies advocated for the continued use of the iBoxx Utilities 10+ index, noting that it helps to mitigate volatility from sectors unrelated to the UK energy sector and more accurately reflects the energy sector.

2.57 Although we recognise that the non-financial indices have a greater exposure to sectors unrelated to the UK energy sector, we share the view that a broader base of debt costs helps reduce the overreliance on the stability or volatility of any one sector.

2.58 Two companies noted that taking the weighted average of the two indices resulted in a credit rating slightly higher than the notional and therefore underestimated the debt costs of the energy networks.

2.59 We acknowledge that the weighted average of the two non-financial indices results in a slightly higher overall average credit rating compared to the utilities index. However, our assessment shows that the majority of the weighted average in both benchmark options is rated Baa1/ BBB+ or below, our target rating for the notional company.

2.60 NPg thought the Utilities index remained the most relevant benchmark. It noted that provided the cost of debt is calibrated correctly, the impact of the choice of index is limited to how that cost of debt allowance is adjusted over the 5-year price control and that the water yields should not overly distort the movement with a long-term trailing average.

2.61 We recognise that while recent volatility in the UK water sector yields may not significantly distort the overall average across 14-year trailing period, we maintain that notable uncertainty persists within that sector. This uncertainty could continue to influence yields, creating volatility in the Utilities iBoxx during the RIIO-3 price control period. Under the full indexation mechanism, allowances adjust dynamically to market conditions, which could result in a higher cost of debt for energy networks than necessary. Therefore, we continue to consider it is more prudent to use the iBoxx GBP A and iBoxx BBB non-financial 10+ corporate indices. Cadent acknowledged that the Utilities index had been affected by volatility in the UK water sector, but it did not believe there was clear evidence to support a return to the non-financial indices. It also maintained that the Utilities

index remains a better fit for sector debt costs, requiring a smaller calibration adjustment.

2.62 The necessity of applying a calibration adjustment is independent of its size; whether the adjustment is minor or substantial, it remains essential to ensure that the benchmark index aligns with the forecasted efficient debt costs of the notional company. Using the Utilities index versus the non-financial indices results in a non-material calibration reduction for the gas companies.

Notional Index Linked Debt assumptions

2.63 In our Draft Determinations, we proposed the capital structure assumptions presented in Table 4: ILD assumption.

Table 4: ILD assumption

Sector	RIIO-2	RIIO-3
Gas	30%	30%
ET	30%	10%

Final Determinations decision

2.64 We have decided to affirm our proposed ILD assumptions for the RIIO-3 period as outlined in Table 4: ILD assumption.

2.65 We reaffirm our recommendation of a 30% notional assumption for the gas sector, reflecting a stable ILD assumption to facilitate the implementation of the nominal allowance for fixed rate debt and that the assumption broadly aligns with the sector average.

2.66 We reaffirm our reduction of the ET ILD assumption to 10%, from 30%. This more closely aligns to the forecasted sector average and reduces the scope for the inflation leverage effect to reoccur.

2.67 We reaffirm our position that a glide path is not required in respect of this reduction on the basis that most ET companies supported the lower ILD notional assumption.

Stakeholder responses and our rationale

Responses to FQ3: Do you consider our proposed notional ILD assumption to be appropriate?

2.68 Most of the gas companies are supportive of the notional ILD assumption stating it is broadly aligned with the sector average. Cadent noted its support for the inclusion of derivatives in making this assessment.

2.69 The ET companies were supportive regarding the reduction stating that a 10% ILD notional assumption would better align to the average sector ILD proportion, improve financeability by helping to achieve the required cashflow during the RIIO-T3 period and reduce equity issuance costs. SHET reaffirmed its position in the Draft Determination that the ILD assumption should be aligned to actual ILD company structures to fully eliminate leverage effect and avoid the assumption being skewed to the largest TO.

2.70 We consider that the proposal to reduce the notional assumption for ET from 30% to 10% appropriately balances the anticipated trend in ILD positions between companies and does not place a disproportionate weight on any one company. The notional company approach does not aim to replicate actual positions but applies a consistent, hypothetical assumption to prevent disproportionate influence from any single company, ensuring neutrality and proportionality across the sector.

2.71 One network company agreed that a transition mechanism was not necessary because it created additional complexity with little benefit. However, it disagreed that the close out mechanism for RPI to CPIH transition should only apply to the notional ILD assumption of 10% and that it should apply to the licensee's actual proportion.

2.72 We continue to consider it appropriate for the close-out mechanism related to the RPI to CPIH transition to apply only to the notional ILD assumption of 10%, in line with the principles of the notional finance framework. This approach ensures consistency across licensees and avoids introducing company-specific variability into a model designed to reflect sector-wide efficient financing.

Additional cost of borrowing allowances

2.73 In our Draft Determinations, we confirmed that we had incorporated additional data provided by network companies to inform our analysis of the incremental cost of borrowing allowances. On this basis, we proposed a total allowance of 19bps for ET and 25bps for GD and GT.

2.74 NERA, commissioned by the Energy Networks Association (ENA) on behalf of network companies, submitted two reports - one representing the gas networks[8] and the other representing the ET sector, which was marked as confidential.

[8] Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3

Liquidity allowance (including cost of carry and Revolving Credit Facility (RCF) costs)

2.75 The RCF/liquidity allowance is associated with the additional costs tied to liquidity and RCFs. As set out in our proposed approach in our Draft Determinations, it is calculated based on the two-year average of actual RCF and debt data reported by network companies. We then multiply this proportion (i.e. RCF to debt) by our estimate of a suitable RCF commitment fee.

2.76 The allowance for the cost of carry covers the issuance of debt ahead of need, as set out in our proposed approach in our Draft Determinations, is calculated based on the two-year average of actual historical cash, cash equivalents and debt data reported by network companies. We then multiply the cash to debt ratio by the five-year average difference between the benchmark of average iBoxx GBP A and BBB non-financial 10+ indices and the 3-month cash deposit rate. We included 25bps of index adjustment for the gas sector.

2.77 In our Draft Determinations we set out our proposal to merge the cost of carry and RCF cost into a single additional borrowing allowance called the liquidity allowance as the sizing of cash balances and RCFs are likely to be driven by common causal factors.

2.78 The total liquidity allowance we proposed in our Draft Determinations was 13bps for ET and 15bps for GD and GT. From these we proposed that 11bps for ET and 13bps for gas were to cover cost of carry. We proposed that 2bps for both sectors would cover costs related to RCFs.

Final Determinations decision

2.79 In paragraphs 2.80 to 2.85 below, we have set out our Final Determinations position in respect of liquidity allowance. A summary of consultation responses, our position in response to those and the rationale for our decision follows at paragraphs 2.86 to 2.109 below.

2.80 We have decided to consolidate the cost of carry and RCF costs into a single additional borrowing allowance, referred to as the liquidity allowance, as proposed in our Draft Determinations. This reflects our view that the sizing of cash balances and RCFs is likely to be influenced by common underlying drivers.

2.81 We have decided to set the liquidity allowance at 20bps for ET and 22bps for gas. From these, we have decided that 17bps for ET and 19bps for gas will cover cost of carry and 3bps for both sectors will cover costs related to RCFs.

2.82 We have decided to calculate the spread as part of cost of carry equation using a ten-year average of the difference between the benchmark iBoxx GBP A and BBB

non-financial 10+ indices and the 3-month SONIA rate for both sectors. We then have decided to apply cash to debt ratio of 7.7% based on 2-year average historic data from network companies.

2.83 As in our Draft Determinations, we have estimated a suitable RCF commitment fee at the level of 16bps based on an average of actual network company commitment fees over a 2-year period. We then have decided to apply RCF to debt ratio of 10.5% based on 2-year average historic data from network companies. To cover the upfront fees associated with RCFs we have added an allowance of 1bp to the cost of debt for ET and gas sectors.

2.84 In line with our approach in our Draft Determinations, we have decided to exclude the RCFs and cash data provided by two network companies that manage liquidity on an intra-group basis. We consider these data points potentially non-representative because the companies include operations that are either non-regulated or outside the UK. We excluded RCFs and cash data from another company which contains a relatively low amount of cash and cash equivalents but high RCF drawings which we consider to be an outlier. We have continued to include network company group level data where the licensee liquidity is managed as part of a group treasury arrangement where such arrangements do not capture non-regulated operations.

2.85 The summary of the liquidity allowance calculations is presented in Table 5 below. Market data was based on October end average.

Table 5: Summary of the liquidity allowance assumptions and estimates

Parameter	**RIIO-3 FDs GD & GT**	**RIIO-3 FDs ET**
RCF size assumption as % of debt (A)	10.5%	10.5%
Commitment fees (B)	16bps	16bps
Upfront fees associated with RCFs (C)	1bps	1bps
RCF allowance (D=A*B+C)	3bps	3bps
Cash assumption as % debt (E)	7.7%	7.7%
Cost of carry (F)	2.49%	2.19%
Cost of carry allowance (G=E*F)	19bps	17bps
Total liquidity allowance (H=D+G)	22bps	20bps

Stakeholder responses and our rationale

Responses to FQ4: Do you agree with our approach to setting the additional cost of borrowing allowances?

2.86 NERA, in its report on additional cost of borrowing for gas, raised concerns regarding our use of historical data to estimate the cost of carry for RIIO-3, noting that the inclusion of the 2023–2024 period characterised by historically low spreads may not provide a reliable basis for forecasting. Instead, NERA proposed an alternative approach based on forward-looking estimates. As part of its report for gas networks NERA suggested using a flat iBoxx rate of 6.10% and an average overnight SONIA forecast of 3.96%, resulting in a spread of 2.14%. NERA further recommended applying a new debt adjustment of 45bps, which would increase the estimated spread to 2.59%.

2.87 We do not agree with the proposal for gas networks to adopt a cost of carry allowance based on the WACC rates model plus a 45bps Gas Network Premium (GNP). Our approach to debt allowance indexation is designed to mitigate market uncertainty over future debt costs. In contrast, the Additional Costs of Borrowing are estimated for the entire price control period and should reflect long-term trends rather than short-term views. We do not consider the use of the most recent forward curve to estimate yields over a five-year horizon to be sufficiently robust.

2.88 Scottish Power Energy Networks (SPEN) stated that our approach is likely to have understated cost of carry and suggested forward-looking approach, which resulted in a spread of 3.0% over the RIIO-3 period. National Grid Electricity Transmission (NGET) argued that we used substantially lower than normal iBoxx to cash deposit spread rather than the forward market implied spread.

2.89 We acknowledge NERA's and the network companies' arguments regarding the inclusion of periods where the spread between iBoxx and cash deposit rates was abnormally low, which may have a disproportionate impact on the average.

2.90 In response, we have revised our approach to estimating the spread by extending the averaging period of market data. Accordingly, we have estimated the spread using a ten-year average of the difference between the benchmark iBoxx GBP A and BBB non-financial 10+ indices and the 3-month SONIA rate. We consider this approach to provide a more stable and representative measure of long-term financing conditions. This change resulted in increasing spread to 2.19% for ET and 2.49% for gas, including a 30bps index adjustment.

2.91 We consider a historical average to provide better context for the relationship between interest rates and deposit rates, particularly in the setting of the cost of carry at the start of a five-year period. This approach helps smooth out short-term volatility and transient market conditions that may distort forward-looking estimates. By anchoring the cost of carry in longer-term trends, we aim to ensure a more stable and representative basis for regulatory decisions.

2.92 NERA also argues that gas sector will require a higher cash/debt ratio of 10% at RIIO-3 as pre-financing costs should be amortised over shorter bond tenor of 10 years. Furthermore, SPEN did not agree that our assumption that the RIIO-ET2 cash/debt ratio is broadly representative of RIIO-ET3 and argued that RAV growth mandates a higher cash/debt ratio. NGET flagged that basing cash to debt ratio on RAV growth between 2022-2024 leads to underestimation of this ratio. NGET estimated that the cost of carry should be set at 36bps. NERA estimated the cost of carry part of liquidity allowance to be 26bps for gas.

2.93 We do not consider NERA's proposal to increase the cash to debt for gas and for ET to be appropriate. For gas, projected declining RAV growth and higher cash inflows relative to lower expenditure plans suggest that elevated liquidity requirements are unlikely. To better reflect observed market conditions for gas, we have applied a 30bps index adjustment, as discussed further in paragraph 2.22. For ET, while we acknowledge the potential for increased debt issuance, we have not seen compelling evidence that the cash to debt will exceed historical levels.

2.94 SGN has challenged our forward-looking cost of carry estimate, stating that the current assumption is understated due to higher sector credit risk. The company also highlighted several other drivers of higher cost of carry across RIIO-GD3, including increasingly stringent requirements for demonstrating going concern, with auditors applying longer assessment periods in line with FRS 102 and the obligation for companies to certify sufficient liquidity to meet net cash outflows over the next 12-months.

2.95 As further elaborated in paragraph 2.93 we consider cash to debt ratio proposed in our Draft Determinations to be sufficient. The credit rating requirement to maintain 12-months of forward-looking liquidity has always been required to support an investment-grade rating, regardless of whether formally certified. To better reflect observed market conditions for gas, we have applied a 30bps index adjustment when calculating cost of carry.

2.96 SPEN further commented on cost of carry component and suggested that we should provide a re-opener mechanism or annual updates to the spread used to calculate the cost of carry via the Annual Iteration Process (AIP).

2.97 We consider introducing additional complexity would detract from the clarity and transparency of the existing methodology. Our Final Determination approach, which uses a 10-year historical average, offers a stable and representative benchmark for long-term financing conditions. While the Additional Cost of Borrowing component within the Allowed Return on Debt is fixed, our indexation mechanism for the core debt allowance is specifically designed to manage uncertainty around future debt costs.

2.98 NERA raised concerns regarding our methodology for estimating the liquidity/RCF component of the allowance for gas. Specifically, NERA disagreed with our assumption that RCF facilities represent 10% of total company debt. Drawing on a two-year average of actual RCF and debt data reported by network companies, NERA contended that the appropriate figure is 14.6%.

2.99 We have reviewed NERA's proposal regarding the appropriate ratio of RCF facilities to total debt and do not agree with the suggested figure of 14.6%. Based on our representative sample of network companies, excluding those identified in paragraph 2.84, we consider a ratio of 10.5% (rounded to 10%) to be more appropriate for our assessment.

2.100 NERA challenged the assumption that the cost of drawdown on RCFs is zero. Based on its analysis of network company data for the period 2022–2024, NERA reported that companies, on average, drew down 3.1% of their RCF facilities. It argued that the associated utilisation fees and margins should be reflected in the allowance.

2.101 We disagree with the assumption that companies, on average, drew down 3.1% of their RCF facilities. Consistent with our position in our Draft Determinations and informed by our understanding of corporate practice and analysis of historic data submitted by network companies, we continue to view RCF drawdowns as uncommon. This is primarily due to the punitive costs associated with utilisation. Our analysis indicates an average drawdown ratio of approximately 1.5% across the representative group. We therefore consider it reasonable to assume that RCFs are not drawn under normal operating conditions. Consequently, we do not consider it appropriate to include either the utilisation fee or the associated margin in our assessment.

2.102 Furthermore, NERA noted that our approach does not account for other costs associated with RCFs, such as upfront arrangement fees, legal fees, and annual agency fees. While NERA acknowledged that these costs are relatively small, it estimated them to be approximately 1bp making the total allowance proposed by NERA to be 5bps for gas. NGET and SPEN also stated that the RCF component allowance should be set at 5bps.

2.103 We have reviewed NERA's assessment of upfront fees associated with RCFs. Based on this analysis, we consider it reasonable and consistent with prevailing market practice to include arrangement fees equivalent to 30bps of the average RCF size, annuitised over the duration of the price control period. To reflect this, we have added an allowance of 1bp to the cost of debt for ET and gas sectors. Based on the updated assumptions we decided to set the part of the liquidity allowance associated with RCFs at 3bps for ET and for gas.

2.104 One consumer group argues that our approach to setting the cost of carry allowance, broadly in line with the methodology adopted for RIIO-2 and RIIO-ED2, is over generous and reduces incentives for firms to manage liquidity efficiently and instead rewards them for holding large cash balances year-round. It further flags that in its view choosing the very top end of the range over-rewards some companies and does not encourage this cost impact of company structure to be passed on to the companies. It recommends setting the allowance at the mid-lower end of a plausible estimate.

2.105 We base our approach to estimating cost of carry on relying on historic actual data provided by network companies, market evidence and corporate practice. We have improved our methodology and have made minor updates to the methodology compared to RIIO-2 by utilising more frequent and granular data which improved the accuracy and robustness of the estimate. While we recognise the importance of incentivising efficient liquidity management, we consider our approach strikes a fair balance between cost and maintaining robust liquidity.

2.106 NPg referred to NERA's report and noted that we should include a forward-looking approach to spreads between debt costs and the cash deposit rate and review requirements for cash, relative to debt, due to the substantially higher RAV growth and debt issuance over the RIIO-3 period. NPg flagged that we should include drawdown costs when calculating liquidity/RCF allowance.

2.107 We addressed all concerns flagged by NPg as part of our response to NERA's reports in paragraphs 2.86 to 2.103. Based on our rationale, we decided not to include a forward-looking approach to spreads between debt costs and the cash

deposit rate and maintain requirements for cash, relative to debt for both sectors and not to include drawn down costs when calculating liquidity/RCF allowance.

2.108 One consumer group also raised more general concerns regarding the proposed additional cost of borrowing. It noted that the allowance appears significantly higher than the level set by the Competition and Markets Authority (CMA) in its PR19[9] redetermination for the water sector. Given that water has been used as a comparator for other metrics, it considered this approach inconsistent. It also questioned the reliance on self-reported transaction and liquidity costs in setting the allowance, highlighting a lack of clarity on whether the adjustment components are independent and individually justified.

2.109 Our assessment draws on historic data provided by network companies and analysis submitted by NERA on their behalf, which we consider to be the most representative of the sector. Some elements of the analysis also use market data. Differences in methodologies between our and Ofwat's approaches, and timing of assessments mean that our results vary from those presented by the CMA in its PR19 redetermination. We note that, in its PR24 Provisional Redetermination, the CMA provisionally included an additional borrowing cost allowance of 20bps.[10]

Transaction costs allowance

2.110 The allowance for transaction costs reflects both ongoing and up-front costs in relation to debt issuance including underwriting/arrangement/listing fees, rating fees and legal fees.

2.111 In our Draft Determinations we proposed setting the allowance for ET networks at 5bps and the allowance for GD and GT networks at 7bps.

Final Determination decision

2.112 We have decided to set the allowance for ET networks at 5bps and the allowance for GD and GT networks at 7bps. We consider analysing transaction costs for electricity and gas sectors separately to be appropriate due to divergences in observed issuance trends in each sector and to ensure consistency in approach between the two sectors. This diverges from the NERA's original approach in which the allowance for ET networks was estimated based on the historical transaction costs data for all networks while proposing a bespoke approach for gas based only on GDN data.

[9] CMA - Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations, final report
[10] CMA PR24 Provisional Determinations Volume 4: Allowed Return, Risk & Return, Provisional Determinations, Next steps - Chapters 7–10, paragraph 7.698

2.113 We have determined the allowance aligning to observed sectoral averages using data provided by NERA, which was submitted by network companies as supporting evidence ahead of our Draft Determinations. This data captures the fees associated with individual instruments and annuitises them over the respective instrument lives. To inform our estimates, we decided to use a GD&GT-only group for the GD&GT allowance and an ED&ET group for the ET allowance. We have excluded one significant outlier when estimating the allowance for ET networks.[11] This modification provides a more representative estimate of a notional efficient operator's transaction costs.

Table 6: Summary of the transaction costs allowance

	RIIO-3 FDs GD & GT	**RIIO-3 FDs ET**
Transaction costs	7bps	5bps

Stakeholder responses and our rationale

2.114 NERA, representing the gas networks, disagreed with our assessment that shorter-tenor bonds typically incur lower arrangement and underwriting fees. NERA contended that our analysis, which identified a positive correlation between bond tenor and transaction costs in absolute monetary terms, was not appropriate. Instead, NERA argued that transaction costs should be assessed on an annuitised basis and expressed as a percentage of the debt issuance amount, to align with the approach used in setting the transaction cost allowance. NERA stated that upfront transaction costs are recovered over the life of the bond and that the allowance is determined as a percentage of the notional debt amount. On this basis, NERA presented analysis indicating a negative correlation between bond tenor and transaction costs when annuitised.

2.115 In addition, NERA noted that our analysis considered only a subset of total transaction costs, specifically arrangement and underwriting fees, while excluding other material components such as rating agency fees, legal fees, auditor fees, and listing fees.

2.116 Based on its revised analysis and the expectation of shorter average debt tenor for gas networks of 10-years during RIIO-3, NERA proposed that the transaction cost allowance should be increased to 8bps for gas networks.

2.117 Responding to NERA's point that transaction costs should be assessed on an annuitised basis and expressed as a percentage of the debt issuance amount, we

[11] The data of this network company was excluded due to its non-representative of future transaction costs nature.

agree with NERA and confirm that our analysis is performed on an annuitised basis. We also reviewed NERA's argument that our analysis considered only a subset of total transaction costs, specifically arrangement and underwriting fees, while excluding other material components such as rating agency fees, legal fees, auditor fees, and listing fees and decided to include these costs. Overall, we agree that shorter-tenor debt can result in a higher effective financing cost over time due to the need for more frequent refinancing.

2.118 Based on the evidence provided, we updated our analysis for the gas sector based on the data provided by NERA and updated it by adding one company that is part of the gas sector but was initially excluded by NERA. We then annuitised it over the period of 12-years which is the average tenor of the most recent bonds issued after 2023 in gas sector, and we consider it a more reliable assumption than 10-years. The updated analysis resulted in the transaction cost allowance of 7bps for gas.

2.119 Cadent stated that, in practice, it does not observe lower transaction costs for shorter-tenor issuances.

2.120 We updated our methodology for gas networks and based our approach on the data provided by NERA, updated it by adding one company that is part of the gas sector but was initially excluded by NERA. The updated analysis resulted in the transaction cost allowance of 7bps for gas.

CPIH basis risk mitigation

2.121 This allowance reflects hedging costs associated with RPI/ CPIH basis risk resulting from the switch indexation of the RAV from RPI at RIIO-1 to CPIH at RIIO-2.

2.122 In our Draft Determinations we proposed basing the allowance solely upon the cost assumption of an RPI-CPI basis swap. We stated that this represents the lowest cost estimate available from the evidence submitted to manage this risk, and we were not aware of any factors that would prevent this approach from being adopted for both new and embedded debt. Based on company submissions, we considered this approach to be better aligned with observed average company behaviour. Accordingly, we proposed an allowance of 1bp for ET and 3bps for GD and GT.

Final Determination decision

2.123 We have decided to provide an allowance based solely on the cost assumption of an RPI-CPI basis swap. This represents the lowest cost estimate among the evidence submitted for managing this risk. As stated in our Draft Determinations,

we remain of the view that there are no material barriers to the adoption of this approach for both new and embedded debt.

2.124 After careful consideration of stakeholders' responses, we decided to set the CPIH basis risk mitigation allowance at 1bp for ET and 3bps for gas.

2.125 The RPI-CPI swap cost assumption of 15bps is derived from NERA analysis submitted by companies as evidence. We decided to introduce a modifier to take account of the RPI methodology transition to the CPIH methodology from February 2030. The modifier is a fraction applied to the cost estimate based upon the number of months that RPI is expected to remain on the current methodology over RIIO-3 (46 months) over the total number of months in RIIO-3 (60 months). To compute the final allowance, we then decided to multiply the modified cost estimate by the ILD notional assumption, 30% for gas and 10% for ET.

2.126 We have decided not to provide an allowance for the CPI/CPIH element of basis risk, consistent with our position in our Draft Determinations and RIIO-2. This decision reflects the fact that no company currently undertakes active hedging of this risk. Furthermore, we consider the likelihood of outperformance and underperformance to be broadly balanced, or potentially favourable to companies. It is also important to note that companies with exposure to CPI-linked instruments may benefit if CPI remains below CPIH.

Table 7: Summary of the CPIH basis risk mitigation allowance assumptions and estimates

	RIIO-3 FDs GD &GT	**RIIO-3 FDs ET**
RPI/ CPI Swap Cost Assumption (A)	15bps	15bps
RPI Methodology Modifier (B)	76.67%	76.67%
ILD Assumption (C)	30%	10%
Total Allowance (A*B*C)	3bps	1bp

Stakeholder responses and our rationale

2.127 NERA has raised concerns regarding our approach to estimating the RPI-CPI basis risk for gas networks. Specifically, NERA disagreed with our assumption that companies will exclusively issue RPI ILD and RPI-CPI swaps, with an assumed cost of 15bps, as it argues that most of the gas networks do rely on issuing synthetic CPI-linkers. NERA states that the cost associated with structuring a nominal-CPI inflation swap are in the range of 30-50bps. Based on these assumptions NERA estimates a CPIH basis risk mitigation allowance of 3-6bps for gas networks.

2.128 We have reviewed the additional evidence submitted by NERA in its latest report. However, we do not consider this evidence sufficiently compelling to justify a departure from the position set out in our Draft Determinations.

2.129 NERA highlighted practical limitations of issuing RPI ILD and then entering RPI-CPI swaps referring to the fact that RPI ILD markets are generally less liquid, making issuance more challenging and costly. NERA argues that as a result, companies often view synthetic CPI-linked debt as a more cost-efficient and flexible alternative. NERA also noted that our assumed allowance of 15bps does not account for the liquidity costs associated with issuing RPI ILD and subsequently swapping to CPI. NERA argues that this results in under-compensation for companies.

2.130 We acknowledge NERA's observation that most gas networks rely on issuing synthetic CPI-linked instruments. However, we do not consider this practice to be a targeted approach to hedging solely basis risk. We consider it part of a broader cost management strategy rather than a risk mitigation tool specifically aimed at addressing CPIH basis risk. Therefore, we do not consider it appropriate to include it as part of the CPIH basis risk mitigation allowance.

2.131 Cadent supports the continued inclusion of an allowance to recognise RPI-CPIH basis risk following the transition to a CPIH-linked price control framework under RIIO-2. It acknowledges that the structure of this allowance will require modification under RIIO-3 to reflect the planned reform of RPI in February 2030, but it considers a duration of 47-months to be more appropriate than 46-months, given the current uncertainty regarding the precise timing of implementation within February 2030. While Cadent agrees that the cost of RPI-CPI basis swaps is a suitable proxy for estimating the basis risk, it does not support the proposed disallowance of new CPI-linked debt. Cadent argues that CPI issuance remains a credible and viable financing route and supports NERA's estimation highlighting that this translates to a total cost of up to 6bps for CPIH basis risk mitigation.

2.132 We do not consider Cadent's point regarding the relevant modifier of 47-months to be more appropriate than 46-months because according to OBR the transition will take place from February 2030 which indicates the change will begin at the start of February. This is aligned with our approach to estimating inflation wedge when calculating risk-free rate (RFR) parameter.

2.133 NGN considers that the cost for managing CPI(H) basis risk needs to be allowed at c. 5bps which is an average between the bottom end of the NERA's range of 3bps based on managing basis risk based on RPI-CPI swaps and the top end of

the range of 6bps based on the prevailing practice of swapping nominal debt to CPI.

2.134 We thoroughly reviewed our approach and decided to base the allowance solely upon the cost assumption an RPI-CPI basis swap which resulted in 3bps for gas.

2.135 National Gas supports NERA's approach but notes that the most recent market data and quotations received for actual transactions indicate higher costs which National Gas argues to be up to approximately 21bps for RPI/CPI swaps and up to 64bps for new synthetic CPI issuances. National Gas suggests that there may be merit in reassessing the cost assumptions underpinning the allowance at Final Determinations. It further notes that the absence of a mature market for hedging CPI-CPIH does not eliminate the risk or associated cost to companies and suggests that a more comprehensive consideration of this risk would represent a positive development in line with the investability principle.

2.136 The RPI-CPI swap cost assumption of 15bps is derived from NERA analysis submitted by companies as evidence and we consider this to be a reasonable estimate of the cost associated with managing RPI-CPI basis risk. As mentioned in our Draft Determinations, we note that no company actively hedges CPI-CPIH risk, and we consider the risk of outperformance and underperformance is at least broadly equally likely or is favourable to companies. Therefore, we decided not to provide an allowance for the CPI/CPIH element of basis risk in line with RIIO-2.

Treatment of inflation

2.137 In our Draft Determinations, we implemented Inflation Option 1: nominal allowance for fixed rate debt and applying this in proportion to the notional capital structure fixed rate debt assumption. In our SSMD, we stated that we consider Option 1 to be better suited to the strategic challenges of RIIO-3, and that it aligns the cash allowance with the servicing requirements of fixed rate debt capital, and we expect the option over the long run to result in lower costs for consumers.

2.138 We also set out in our Draft Determinations that we did not consider that a transition mechanism is required, noting that this minimises complexity, aligns to the notional approach and removes the inflation leverage effect on a notional basis immediately. In addition, we do not consider there to be evidence of a detrimental impact, on a notional basis, to financial resilience from implementing Option 1 in line with the current notional cap structure.

2.139 Regarding deflation of the ILD assumed portion, in our Draft Determinations we proposed adopting the Bank of England CPI inflation target (2%) as opposed to the 5th year of the prevailing OBR CPI forecast as the long run assumption as in RIIO-2. The 5th year OBR forecast is usually aligned to 2%. We also stated that we would review whether an adjustment to the inflation assumption and CPIH basis risk allowance is warranted to reflect a report published in October 2024 by the OBR implying long-run wedge between CPI and CPIH of 0.4%.

Final Determinations decision

2.140 We have decided to implement Inflation Option 1: nominal allowance for fixed rate debt and apply this in proportion to the notional capital structure fixed rate debt assumption. Our rationale is further explained in the RIIO-3 SSMD. [12]

2.141 To maintain consistency with our approach in RIIO-2 and the treatment of inflation in RIIO-3, we have decided to use the OBR's 5th year CPIH forecast to deflate the ILD portion of assumed debt, now that these forecasts are available. This replaces the Bank of England's target rate of 2% as proposed in our Draft Determinations. Our analysis of historic data indicates there is an average difference between CPI- CPIH of 0.06% between 1998-2024. We will retain the RIIO-2 approach of using CPI for years preceding the publication of CPIH

Stakeholder responses and our rationale

Responses to FQ5: Do you agree with our proposed treatment of inflation with respect to the allowed return of debt?

2.142 Most respondents who commented on the transition to a semi-nominal allowance support its implementation at the start of RIIO-3.

2.143 NPg responded that it supports an immediate move to a fully nominal allowance for the notional company's fixed portion of its debt book.

2.144 One consumer group agreed with the proposed treatment of inflation with respect to the allowed return of debt, however, noted there was still a chance for a windfall to be gained on the ILD assumed portion. It noted that inflation assumption used to deflate nominal yields may under-state long-term CPIH expectations, which would make the allowed return on debt too high. It also noted that companies with exposure to CPI-linked instruments stand to benefit from the discrepancy with CPIH indexation based on the OBR's assumed long-run wedge between CPIH and CPI being 0.4%. Lastly, it commented that the

[12] RIIO-3_SSMD_Finance_Annex, page 34

indexation of debt provides further protections to UK network companies that is not always granted elsewhere, for example in the US regulated energy sector.

2.145 Respondents agreed with the proposal to use the Bank of England target rate of 2% however, they did not consider the use of the OBR's CPIH–CPI wedge to be appropriate, with most referencing Oxera's analysis in support of their position. Please refer to the FQ8 response (paragraph 3.25).

2.146 After assessing whether an adjustment to the inflation assumption and CPIH basis risk allowance was warranted to reflect the OBR's long-run wedge, we have concluded that the current assumptions do not provide a strong enough foundation to support applying the wedge. On balance, we do not consider the adjustment to be justified at this time however, we will continue to monitor developments and will consider revisiting this position once the OBR have further developed its methodological approach. We have instead opted to, in line with RIIO-2, to use the 5th CPIH forecast which also maintains consistency across RIIO-3.

2.147 One supplier disagreed with not providing a transition mechanism. It argued that consumers will face higher upfront costs from April 2026 under the new arrangements if they are implemented straight away. It believed phasing the transition mechanism in would help mitigate the overall immediate impact on bills and avoid the likely disruption to elements of the retail market from the resultant abrupt increases in network charges.

2.148 We have considered the supplier's concerns regarding the potential impact of implementing the new arrangements from April 2026 without a transition mechanism. As we noted in our Draft Determinations, the inflation leverage effect currently presents a risk of consumer detriment and a delay to implementation would potentially result in consumers being exposed to this risk for longer than necessary. We do not consider the benefit to consumers is sufficiently material to warrant a phased approach to this important protection. However, recognising the step change in allowed revenues from RIIO-2 to RIIO-3 and its potential impact on the non-domestic supply market, we have set out our targeted revenue profiling decisions in Chapter 10.

Infrequent issuer allowance

2.149 The infrequent issuer premium reflects an increase in the cost of new debt for those licensees, on a notional basis, that are expected to issue smaller size new debt or issue new debt less frequently than other networks, due to their smaller RAV sizes and/or lower RAV growth for RIIO-3.

2.150 In our Draft Determinations, we applied the same threshold of £250 million in average annual notional debt issuance that was used in the ED2 Final Determinations. Based on this threshold, we identified four companies - SGN Scotland, SGN Southern, WWU, and NGN as infrequent issuers who would be expected to issue, on average, less than £250 million per annum on a notional basis.

2.151 In our Draft Determinations we proposed not providing a distinct infrequent issuer allowance in RIIO-3. We consider that, to the extent that additional costs are incurred due to infrequent issuance, these are already broadly captured within the dataset used to calibrate the main cost of debt allowance as well as the gas new debt assessment. Therefore, we considered that, providing a distinct infrequent issuer allowance would risk duplicating cost recovery and lead to overcompensation of companies.

Final Determinations decision

2.152 We have decided that, to the extent an infrequent issuance premium is incurred, it is already sufficiently captured within the calibration of the main cost of debt allowance. As such, we reaffirm our position set out in our Draft Determinations and will not continue a separate allowance for infrequent issuers. We consider that providing an additional allowance would present a material risk of overcompensation of companies.

Stakeholder responses and our rationale

Responses to FQ6: Do you agree with the removal of the infrequent issuer allowance?

2.153 Four network companies did not express strong views on the proposal to remove the infrequent issuer allowance. Some indicated that they would support retaining the allowance if there were robust evidence to justify its need. Others noted that they had not reviewed the supporting analysis in detail, as the proposed change would not directly impact them.

2.154 One consumer group agreed with the removal, stating that the infrequent issuer allowance has generated an unjustified premium in previous price controls.

2.155 Scottish Power Transmission (SPT) broadly supported the removal of the infrequent issuer allowance, given the scale of its planned investments over the RIIO-3 price control period. SPT viewed it as inappropriate to use its financing profile as a proxy for infrequent issuers when assessing the need for additional borrowing cost allowances.

2.156 Two GDNs, and one DNO did not support the proposed removal of the infrequent issuer allowance. NPg considered the approach taken in RIIO-ED2 to be appropriate. It suggested that, if we had concerns about maintaining the allowance in its current form, it should consider alternative options, such as introducing a tapered allowance or adjusting the threshold, rather than removing the allowance entirely. NGN highlighted that, as an infrequent issuer, it relies on derivatives for interest rate hedging. NGN argued that without the ability to issue debt frequently, it cannot align its actual debt costs with the cost of debt allowance through issuance alone. As a result, it incurs additional costs compared to frequent issuers and believes these should be recognised through a dedicated allowance. NGN also noted that infrequent issuers are more likely to face higher costs of carry, as they often need to raise debt in advance of funding requirements. Both NGN and the other respondents, referenced the analysis conducted by NERA, discussed further in the below paragraphs, as supporting evidence for maintaining some form of infrequent issuer compensation.

2.157 We acknowledge that derivatives can be an effective tool in financial strategies and may be practical when employed to synthetically replicate debt instruments. We do not however, consider them essential for maintaining an efficient capital structure. We conclude that their use depends on an issuer's financing strategy, risk appetite, and the broader sector context and that ultimately, they do not create the same contractual obligations or risks of an actual debt instrument. While they can help manage interest rate risk, derivatives also introduce additional costs and complexities, including, but not limited to, transaction fees, operational challenges, and the potential to incentivise financial engineering. Moreover, infrequent issuers may not always benefit from using derivatives, particularly if the costs outweigh the potential alignment with regulatory benchmarks. In some cases, infrequent issuers may benefit from their ability to time the market, issuing debt when interest rates are low and avoiding issuance during periods of high rates, an advantage not typically available to frequent issuers. As such, the use of derivatives should not be assumed to be a necessary or universally beneficial strategy for managing debt costs.

2.158 NERA provided analysis estimating an infrequent issuer premium with a mid-point of 6bps. This estimate was based on two approaches: the illiquidity premium associated with sub-benchmark bond issues, which suggested a premium of approximately 3.5bps, and analysis using Constant Maturity Swaps (CMS). NERA also concluded that the sample used to calibrate the gas new debt allowance only included 57% infrequent issuers on a volume-weighted basis. As such, they

argued that the sample was not sufficiently representative to fully capture the additional costs faced by infrequent issuers.

2.159 We recognise that some issuances may incur higher costs due to infrequency or smaller size. However, these costs are reflected in the credit spreads of the sample used to calculate the new gas debt adjustment, with the majority of the sample representing infrequent issuers on a volume-weighted basis. As such, the cost of debt allowance already incorporates these costs in aggregate. Introducing a separate adjustment would risk double-counting and this is not justified by the evidence provided.

2.160 NERA noted that the 6bps allowance provided in RIIO-2 was based on evidence derived from CMS. It challenged our position in RIIO-3 that companies should not be compensated for CMS-related risks simply because not all companies use CMS. NERA argued that the absence of CMS usage does not negate the underlying risk exposure faced by companies. It maintained that such risks are incurred regardless of whether firms choose to hedge them and that CMS provides a basis for estimating the infrequent issuer premium that is unrelated to the gas network premium and therefore not captured within the main cost of debt allowance. It also cited bank estimates indicating CMS-related costs that would support an infrequent issuer premium of 9bps.

2.161 CMS instruments are not commonly used in practice, and the associated costs, like other derivative products, often exceed the specific cost of the risk it is intended to mitigate. To the extent that an infrequent issuer premium exists, it would be reflected in the credit spread, which companies cannot actively hedge against. Taking this into account and what is outlined above, we consider that the gas new debt adjustment, together with the overall calibration of the cost of debt allowance, already captures the costs faced by infrequent issuers

2.162 NERA presented analysis based on the relative spreads at issuance for a sample of energy network debt. It argues this analysis shows an illiquidity premium of 21–24bps for sub-benchmark sized issues compared to those at or above £250 million. On this basis, it claims this supports an infrequent issuer premium of around 7bps.

2.163 NERA did not provide sufficient detail on its underlying sample to validate the claimed infrequent issuer premium. Without robust evidence, we do not consider that this supports an additional adjustment beyond what is already reflected in our approach.

3. Allowed return on equity

Purpose: Returns to equity investors remunerate their investment in network services and comprise a baseline allowance plus performance incentives. In this chapter we outline the steps we have taken to set the baseline allowance.

Benefits: Accurate remuneration will secure network investment during RIIO-3 and help keep consumer charges in line with efficient costs.

Final Determinations summary

Equity steps and parameters (CPIH-real)	60% notional gearing	55% notional gearing
Risk-free rate forecast (Oct)	2.30%	2.30%
Total market returns	6.9%	6.9%
Equity beta	0.83	0.74
CAPM implied cost of equity	6.12%	5.70%
Step-2 cross checks	Supportive	Supportive
Step-3 baseline allowed return	6.12%	5.70%

Source: Ofgem analysis

Step-1 CAPM calculations

Risk-free rate (RFR)

3.1 In our Draft Determinations, we proposed using RPI index-linked gilts (ILGs), adjusted to real terms using CPIH, as the basis for the RFR assumption.

Final Determinations

3.2 We have decided to set the RFR for each year of the price control based on the one-month average of the 20-year ILG yield. This will be done in the October preceding the commencement of each year of the price control.

3.3 We have decided to adjust RPI-real ILG yields to CPIH-real terms based on a 'wedge' calculated primarily using the official forecast methodology described in our SSMD. We have adopted the use of CPIH forecasts in our wedge estimation methodology, following the Office for Budget Responsibility's (OBR) introduction of these forecasts.

3.4 We have decided to continue to 'index' the overall allowed return on equity by the annually updated RFR used within our CAPM for RIIO-3.

Table 8: RFR based on September 2025 data

Risk free rate	Value
20-year ILG	2.21%
Inflation wedge	0.09%
RFR	2.30%

Source: Bank of England, OBR

Stakeholder responses and rationale

Responses to FQ7: Do you agree with our methodology for calculating the RFR?

3.5 All the network companies stated that a convenience premium should be added to ILGs when calculating the RFR, citing analysis by Oxera.[13] Additionally, SGN referenced work by KPMG,[14] while SPT referred to analysis by NERA.[15]

3.6 We carefully considered network companies' submissions and the associated information. However, we concluded that there is insufficient compelling evidence to support the use of alternative RFR proxies or manual adjustments to ILG yields within our CAPM framework. As noted in the CMA's PR24 Provisional Determinations while the concept of a convenience yield is recognised in academic literature, its magnitude, especially for UK longer-dated index-linked assets, is difficult to estimate with precision.[16] Our approach prioritises transparency, replicability, and consistency with market evidence. Accordingly, we continue to rely on ILG yields as the primary input for estimating the RFR, without applying a convenience premium.

3.7 Both Oxera and KPMG referenced academic evidence supporting the presence of convenience yields in short-term UK gilts. In both cases the academic evidence relates to short maturities and does not provide sufficient evidence to support applying a positive convenience yield to longer-dated ILGs. The UKRN's Cost of Capital Taskforce highlights that there are no empirical estimates of the convenience yield for ILGs at the 10–20-year investment horizon typically used by regulators under the CAPM framework.

3.8 To estimate the convenience premium, Oxera applied the same methodology used in its previous reports. The analysis involved comparing the five-year

[13] Oxera, RIIO-3 draft determinations - CAPM parameters and debt-based cross-checks - prepared for the ENA (August 2025),
[14] KPMG, Estimating the risk-free rate for RIIO-3 (August 2025),
[15] NERA, Cost of Equity for RIIO-T3 for Scottish Power Transmission (August 2025)
[16] CMA PR24 Provisional Determinations Volume 4: Allowed Return, Risk & Return, Provisional Determinations, Next steps - Chapters 7–10,paragraph 7.176.

average yields of the iBoxx £ AAA non-gilt 10+ and 10–15 indices with the five-year average yields of AAA-rated gilts with maturities of 9.5 and 14.0 years. This approach produced a convenience premium estimate of 0.24%.

3.9 As noted in our SSMD, the iBoxx AAA indices are thinly populated, with limited market coverage and a high proportion of foreign-issued instruments. The iBoxx £ AAA non-gilt 10–15 index comprises only five issues from three issuers, while the 10+ index includes twelve issues from five issuers, the majority of which are non-UK entities. Moreover, the maturity and duration profiles differ materially from the 20-year ILGs used in our RFR estimation. These limitations undermine the robustness of the convenience premium estimate and reinforce our view that ILG yields remain the most appropriate input for estimating the RFR.

3.10 Oxera restated its view that the convenience premium should be estimated by comparing the yields of AAA-rated non-government bond indices with those of duration-matched nominal gilts. Oxera noted in its report none of the available indices had an average duration of 20 years and it proposed basing the analysis on the 10+ and 15+ indices with an average duration of 14.20 and 17.60 years, respectively. Oxera stated that the previous approach of adjusting AAA non-government bonds for higher liquidity and credit risk has been superseded by this simpler yield comparison method, due to the significant uncertainty involved in estimating liquidity and credit risk premia. It argues that credit risk is already reflected in bond yields through their credit ratings.

3.11 As Oxera notes, it is unable to match the duration of AAA-rated non-government bond indices with the duration of 20-year index linked gilts. This limits their suitability as a comparator for 20-year gilt yields. Although there is significant uncertainty in estimating liquidity and credit risk premia, these factors are present and should not be overlooked when comparing AAA-rated non-government bond indices with zero-coupon gilts.

3.12 Oxera states that the liquidity differences between gilts and AAA-rated non-government bonds do not undermine the existence of a convenience premium; rather, they are a key driver of it. Specifically, the premium arises in favour of the more liquid asset-government bonds.

3.13 We set out detailed analysis in our SSMD[17] which showed that after adjusting for credit and liquidity risk premia, AAA non-corporate bonds would trade at yields at or below the comparable gilt yield. This suggests that our methodology of

[17] RIIO-3 SSMD Finance Annex, paragraphs 3.49 – 3.50.

focusing on solely ILGs is likely to provide a sufficiently accurate estimate of the RFR.

3.14 KPMG also flagged several factors supporting convenience yields: strong demand from liability-driven investors for long-dated ILGs; the higher collateral value of gilts compared to other maturity-matched safe assets at longer tenors; and Diamond and Von Tassel's observation that the convenience yield tends to rise with interest rates - rates which have increased significantly in the UK.

3.15 While we note strong demand from liability-driven investors for long-dated ILGs, KPMG's interpretation may be implausible. The value of longer-dated securities is sensitive to interest rate changes which diminishes their effectiveness as collateral. We further note that Oxera, in its November 2022 response to the UKRN consultation,[18] proposed applying a 50-100bps convenience premium to UK ILG yields when estimating the RFR, at a time when market rates were materially lower than they are today. More recently, in responses to our Draft Determinations, Oxera estimated the convenience yield at 24bps, while KPMG suggested 42bps. These varying estimates highlight the challenge in establishing a consistent or positive correlation between convenience yields and prevailing interest rates.

3.16 The network companies' consultants also flag existing differences between borrowing rates available for private borrowers and the government. Oxera notes that yields on top-rated corporate bonds (AAA-rated) are typically higher than those on government bonds of equivalent maturity. As such, Oxera considers it important to account for this convenience yield when estimating the RFR, by incorporating highly rated corporate bonds into the analysis. Also, KPMG estimates the RFR by adjusting the ILG yield to account for both a convenience yield and the spread between investors' risk-free saving and borrowing rates. By summing these, KPMG derived a point estimate of 42 bps, which they add to the 20-year ILG yield to estimate the RFR. KPMG also notes that an inflation wedge is added on top of this.

3.17 Consultants' view regarding the difference between borrowing rates available for private borrowers and the government draws on the Brennan CAPM framework, which recognises that investors face different borrowing and lending rates, and suggests that the appropriate RFR lies between the two. While we acknowledge that Brennan CAPM is a recognised theoretical model, it remains one of several

[18] Oxera, A review of the methodology used to estimate the allowed cost of equity for regulated companies

approaches. The Sharpe-Lintner CAPM, which assumes a single RFR accessible to all investors, is widely used by regulators and practitioners due to its simplicity and transparency. As noted by the CMA in their PR24 Provisional Determinations, both models are theoretically valid. Given the practical challenges in estimating a precise convenience premium and the lack of consensus on its magnitude, we continue to rely on the Sharpe-Lintner CAPM framework. This approach supports the use of observable ILG yields as the most appropriate input for estimating the RFR.

3.18 NERA stated that we had not addressed the issue of excess structural demand, which it argues leads to understated ILG yields. This is evident from breakeven inflation data and supported by a broad base of literature and empirical evidence.

3.19 As noted in our Draft Determinations, we agree with the CMA's finding that the observed price differences between nominal gilts and ILGs are more likely driven by factors such as aggregate inflation expectations, liquidity risk premiums, and inflation risk premiums.[19] Due to limited transparency around the relative contribution of these factors, it is difficult to isolate and quantify their individual impact, and therefore challenging to incorporate them reliably into the assessment of the true RFR.

3.20 Oxera reaffirmed its position that there is precedent for recognising a convenience premium, noting that the CMA, in its RIIO-2 appeal decisions, acknowledged evidence supporting its existence.

3.21 While we recognise that the CMA acknowledged empirical evidence for a convenience yield in nominal bonds with short tenors across developed economies in their PR24 Provisional Determinations they also stated that it is difficult to estimate with any precision what the likely convenience yield is for UK longer-dated index-linked assets. Given the fact that RFR is one of the most observable CAPM parameters, the CMA cautioned that subjective adjustments may not improve its accuracy. We further note that Ofwat, in its PR24 Final Determinations, chose not to apply a convenience yield adjustment to RPI-linked gilts, citing insufficient relevant evidence to support such an approach.[20] This position was also reflected in the CMA's PR24 Provisional Determinations, where the CMA provisionally concluded that no adjustment for a convenience yield was

[19] CMA Final determination: Volume 2A: Joined Grounds: Cost of equity (2021), paragraph 5.139
[20] PR24 Final Determinations – Aligning risk and return, allowed-return appendix, page 16

justified.[21] Additionally, the Civil Aviation Authority (CAA), in its Cost of Capital Strategy for H8,[22] proposed the removal of convenience yield adjustments when estimating the RFR, as part of its discretionary recommendations for the H8 methodology.

3.22 We carefully considered network companies' submissions and the associated information. However, we concluded that there is insufficient compelling evidence to support the use of alternative RFR proxies or manual adjustments to ILG yields within our CAPM framework.

Responses to FQ8: Do you agree with our methodology for calculating the inflation wedge?

3.23 The majority of network companies expressed support for our methodology in calculating the inflation wedge. However, NPg suggested that the RPI inflation lag should be reflected in the treatment of index-linked gilts.

3.24 While we recognise NPg's rationale, we consider the potential impact to be negligible. Moreover, introducing additional complexity would detract from the clarity and transparency of the existing methodology.

3.25 Network companies generally did not consider the use of the OBR CPIH–CPI wedge to be appropriate, with most referencing Oxera's analysis in support of their position. Oxera considered our approach to calculating the inflation wedge appropriate. However, it did not support including the OBR's CPI–CPIH wedge in the estimation of the RFR, citing three key reasons: first, historical evidence does not support the existence of a stable or predictable wedge; second, the drivers behind long-term CPIH projections are conceptually complex and highly uncertain; and third, CPIH forecasts have only recently been published by the OBR, starting with its October 2024 report, making it a largely untested measure.

3.26 We acknowledge the arguments presented by network companies and Oxera and have decided not to apply a CPI-CPIH wedge. Instead, we use the OBR year 5 CPIH forecast, as it aligns with the duration of the price control period. We consider this approach to be more consistent with market-based expectations for long-term inflation and interest rates, which are key inputs into the cost of capital assessment.

[21] CMA PR24 Provisional Determinations Volume 4: Allowed Return, Risk & Return, Provisional Determinations, Next steps - Chapters 7–10, paragraph 7.70
[22] CCA - Cost of Capital Strategy for H8, table 2

Total Market Returns (TMR)

3.27 In our Draft Determinations, we proposed a TMR range of 6.8% to 6.9% in CPIH-real terms, with a midpoint of 6.9% (the midpoint is 6.85% rounded to one decimal place).

Final Determinations

3.28 We have decided to retain our Draft Determination position and set a TMR range of 6.8% to 6.9% in CPIH-real terms, with a midpoint and point estimate of 6.9% (the midpoint is 6.85% rounded to one decimal place).

3.29 We have set the TMR range using both ex ante and ex post estimates, presenting it as 6.8% (from the ex ante analysis) to 6.9% (from the ex post analysis).

3.30 When setting the TMR, it is important to remember that this figure represents a long-term estimate of expected market returns. On this basis, we present the TMR range and point estimate rounded to one decimal place.

Table 9: TMR range, midpoint and point estimate

TMR Approach	**Result**[23]
Ex ante (arithmetic)	6.8%
Ex post (arithmetic)	6.9%
Midpoint and point estimate	6.9%

Source: Ofgem analysis

Stakeholder responses and rationale

Responses to FQ9: Do you agree with our methodology change in calculating the ex ante TMR?

3.31 One consumer group did not support our methodological change in calculating the ex ante TMR. It opposed the removal of the serial correlation adjustment and disagreed with the change from geometric to arithmetic conversion. In contrast to the network companies, it considered the proposed TMR to be overestimated.

3.32 In response, we acknowledge the ongoing debate regarding the presence of serial correlation in market return data and recognise the challenges in establishing its existence or absence with statistical certainty. Considering this, we have opted not to apply a serial correlation adjustment. Our use of an arithmetic average approach is consistent with guidance found in widely respected corporate finance literature. For instance, Brealey, Myers & Allen, in Principles of Corporate Finance,

[23] Note – rounded to one decimal place

advise that "if the cost of capital is estimated from historical returns, use arithmetic averages, not compound annual rates of return."[24] While the consumer group correctly note that the classical CAPM model assumes the TMR reflects the return on all risky assets, this assumption is widely regarded as impractical. It would require inclusion of numerous obscure assets with no observable prices. To our knowledge, no regulator or financial institution applying CAPM adopts such an approach. Regarding concerns that historical data may overstate future returns, we agree this could be a risk if short time periods with elevated returns were used. However, our estimate is based on over 120 years of market data, which helps mitigate this concern and provides a more robust foundation for our TMR estimate.

3.33 The network companies and their consultants supported our methodological change in calculating the ex ante TMR. However, they consistently argued that minimal or no weight should be placed on the ex ante TMR, advocating instead for greater emphasis on the ex post TMR. All network companies contended that the proposed TMR was set too low and did not adequately reflect the prevailing interest rate environment. In support of their position, they referenced reports from Oxera,[25] Frontier,[26] and NERA.[27]

3.34 Both Oxera and NERA, on behalf of the network companies, agreed with the revisions to our ex ante methodology; however, they arrived at different estimates from each other and from us. Without access to their detailed calculations, we are unable to fully identify or reconcile the differences. The consultants argue that little weight should be placed on the ex ante TMR. We have set the TMR range using both ex ante and ex post estimates. To balance the strengths of each approach and maintain simplicity, we have applied equal weighting to both. We consider that the TMR is appropriately calibrated, supported by our investment manager's long-term market return forecasts and validated through cross-checks against our cost of equity allowance, where TMR is a key input. This approach aligns with regulatory precedent, UKRN guidance, and recent CMA determinations.[28]

[24] Brealey, Myers & Allen, Principles of Corporate Finance (2020), page 170
[25] Oxera, RIIO-3 draft determinations - CAPM parameters and debt-based cross-checks - prepared for the ENA (August 2025)
[26] Frontier Economics Update Cost of Equity Cross-Check Evidence, for the ENA (August 2025)
[27] NERA, Cost of Equity for RIIO-T3 for Scottish Power Transmission (August 2025)
[28] CMA PR24 Provisional Determinations (October 2025),paragraph 7.209

3.35 In support of a higher TMR, Oxera stated that in our previous decisions the TMR allowance was reduced in response to falling gilt yields, with only part of the reduction attributable to the transition from RPI to CPIH. They argued that failing to reflect rising interest rates in the current context is inconsistent. They also argued that our through-the-cycle and fixed TMR approach risks becoming increasingly disconnected from the returns investors require. Oxera also referenced Frontier's updated TMR Glider, which suggests a TMR range of 7.8% to 8.0%, depending on the length of the trailing average. Frontier also provided a dividend growth model (DGM) analysis and TMR survey evidence to support their case for a higher TMR.

3.36 In RIIO-2, our TMR estimate was not explicitly adjusted to reflect prevailing market conditions, and it was higher than estimates provided by investment managers and advisors. Similarly, in RIIO-3, we have not manually adjusted the TMR based on current market conditions. It remains the case that our TMR estimate of 6.9% exceeds the 5.6% average of the long-term market return estimates we have gathered from investment managers and advisors. Please see these in Table 10 below.

Table 10: Fund manager long term market return estimates

Author	Date	Horizon	Nominal TMR	Real TMR
Schroders	Jul-25	10 years	10.7%	8.4%
Quilter	Sep-25	10 years	9.9%	7.7%
Deutsche Bank	Mar-25	10 years	9.1%	6.9%
Invesco	Jan-25	10 years	7.9%	5.7%
Vanguard	Jan-25	10 years	7.7%	5.5%
Capital Group	Feb-25	20 years	7.5%	5.3%
AON	Sep-24	10 years	7.0%	4.8%
BlackRock	Aug-25	10 years	6.6%	4.4%
Ninety One	Mar-25	10 years	6.3%	4.1%
Northern Trust	Jan-25	10 years	5.4%	3.2%
			average	**5.6%**

Source: Ofgem, company websites.

3.37 We do not agree that our TMR estimate should incorporate an uplift to reflect higher market interest rates or an elevated RFR. A stable TMR approach has helped maintain consistency in allowed equity returns—an attribute we consider highly valuable to investors in energy networks, given that energy projects require significant, long-term capital commitments. This consistency also benefits

consumers by reducing the risk of sudden price spikes or volatility, supporting more stable and affordable energy bills. Had we adopted a methodology based on a stable equity risk premium (ERP), the returns allowed under RIIO-2 would have been significantly lower. Adjusting the methodology to shield investors when interest rates are low and then revising it to benefit them when rates rise, would undermine the principle of regulatory neutrality and fail to adequately safeguard consumer interests.

3.38 Frontier's TMR Glider involves estimating a TMR using a DGM. We agree with Frontier Economics that the DGM is commonly used to estimate the cost of equity (CoE). However, we continue to have reservations about its application. The model assumes dividends grow at a constant rate indefinitely—an assumption that is rarely realistic. This is particularly relevant in the electricity sector under RIIO-3, where elevated regulated asset value growth is likely to result in variable dividend patterns, undermining the model's core premise. Moreover, the DGM cannot be applied to firms that do not pay dividends, excluding many growth-oriented companies that now represent a significant and growing share of equity markets. Finally, the model is highly sensitive to both the assumed dividend growth rate and the required rate of return.

3.39 As noted in our Draft Determinations, we already incorporate an investment manager-based TMR cross-check, the details of which are provided in this chapter. In contrast, the Fernandez TMR survey is conducted via email outreach to over 14,000 finance and economics academics, analysts, and corporate managers. For the UK-specific TMR estimate, no information is available regarding the identity or credentials of the respondents. In contrast, our survey incorporates insights from well-established and respected investment firms, offering a robust and credible foundation for validating the TMR.

Beta

3.40 In our Draft Determinations, we proposed setting the debt beta at 0.075 and the asset beta at 0.375.

Final Determinations

3.41 We have decided not to set separate asset betas for each sector. While both sectors have presented arguments highlighting the uniqueness of their respective businesses, we found it difficult to weigh these claims against one another. Importantly, we did not consider any of the additional risks identified to be systematic in nature, nor do we consider they warrant compensation from consumers to investors. Furthermore, the European comparator evidence does

not provide a clear or consistent signal that the market assigns a higher beta to gas companies compared to electricity companies.

3.42 We have decided to retain our Draft Determinations position and set the debt beta at 0.075 and the asset beta at 0.375.

Table 11: Notional gearing, debt beta, asset beta, equity beta

Component	RIIO-GD3 & RIIO-GT3	RIIO-ET3
Notional gearing	60%	55%
Debt beta	0.075	0.075
Asset beta	0.375	0.375
Equity beta	0.83	0.74

Source: Ofgem estimates. Note - may not sum due to rounding.

Stakeholder responses and rationale

Responses to FQ10: Do you agree with our methodology for estimating beta?

3.43 All network companies and one consumer group disagreed with our approach to estimating beta, either with the selection of the point estimate, the choice of comparators, or both. Most network companies referenced analysis by Oxera, while SPT commissioned separate analysis from NERA. [29] [30] [31]

3.44 The consumer group argued that we significantly overestimated the level of systematic risk faced by regulated energy companies. It also questions the use of daily beta measurements, asserting that they are unsuitable for long-term investment horizons. Furthermore, it recommends conducting regression analysis against global equity indices, noting that UK regulated companies may exhibit an upward bias when compared to UK indices. It proposes that the Generalised Autoregressive Conditional Heteroskedasticity (GARCH) model could be more appropriate than the Ordinary Least Squares (OLS) model used in our analysis of raw equity betas. Finally, it highlights that RIIO-3 mechanisms—such as re-openers, pass-throughs, volume drivers, and indexation—serve to reduce the systematic risk borne by network companies.

3.45 The consumer group raises valid questions about whether the level of systematic risk attributed to regulated energy companies may have been overstated.

[29] Oxera, RIIO-3 draft determinations - CAPM parameters and debt-based cross-checks - prepared for the ENA (August 2025)
[30] Oxera, RIIO-GD&T3 cost of equity and debt premium cross-check for ENA (August 2025),
[31] NERA, Cost of Equity for RIIO-T3 for Scottish Power Transmission (August 2025)

Nonetheless, we are confident that our methodology for estimating beta aligns with industry best practice. Furthermore, the results of our approach have undergone rigorous cross-checks to ensure that our application of the CAPM yields cost of capital estimates are consistent with those derived or implied from a range of alternative methods. We agree with the UKRN Guidance that using daily beta data is appropriate for the types of stocks under consideration, as they are typically highly traded and liquid. Compared to weekly or monthly data, daily observations offer a reasonable balance between analytical efficiency and reliability. We do not agree that using global betas would result in a more accurate estimate of the cost of capital. Consistent with the position outlined in the UKRN Guidance, we consider that the most diversified local index denominated in the relevant currency offers the most meaningful insight into the systematic risk faced by energy networks. UKRN Guidance recommends that regulators estimate equity beta using standard regression techniques, such as OLS, accordingly, we apply the OLS method. We share the consumer group's view that risk is most effectively managed at source. Therefore, policy mechanisms such as re-openers, pass-throughs, volume drivers, and indexation play a crucial role in mitigating the risks borne by network companies.

3.46 Oxera argued for a higher beta on several grounds. Electricity networks are expected to make significant capital investments, while gas networks face uncertainty over the future of gas and potential asset stranding. These forward-looking risks, Oxera noted, may not be reflected in historical betas. They also pointed to RIIO-1, where companies with larger investment programmes and greater totex variability were assigned higher betas. Additionally, Oxera reiterated the "low beta anomaly," suggesting that the CAPM framework tends to underestimate returns for low-beta stocks. Oxera also presented evidence that debt markets are pricing in higher long-term risk for gas networks and this should be reflected in a higher asset beta than the electricity networks. Kairos Economics also argued for higher gas betas.

3.47 While we acknowledge that electricity networks are facing elevated capital expenditure during RIIO-3 and that gas networks may encounter asset stranding risks, we do not consider these to be systematic risks. As such, we do not consider consumers should compensate energy network investors for them. In our view, increasing the equity beta—particularly by an arbitrary amount—is not a necessary or justified measure. Oxera shares our view that the new European comparators are exposed to similar risks as the UK energy networks. We

therefore consider that the beta estimate will appropriately capture any changes in risk between RIIO-2 and RIIO-3.

3.48 There are strong reasons to doubt the existence of a lasting 'low beta anomaly'. Most investors believe that any consistent market inefficiencies would be corrected over time. Also, survivorship bias—focusing only on companies that survived—can distort results, especially if riskier, failed firms with higher betas are left out. Behavioural factors like investor irrationality may also explain the anomaly, rather than a true market flaw. For these reasons, we consider it inappropriate to manually adjust the beta estimate.

3.49 In contrast to the evidence in the debt markets we note that, within our beta comparator set, the average beta for gas assets has been lower over the past two years compared to the five- and ten-year averages.

Responses to FQ11: Do you agree with our proposed set of comparators which also incorporates selected European utility stocks?

3.50 One consumer group disagreed with our proposed set of comparators, referencing RIIO-2 evidence that cautioned against the inclusion of European comparators due to differing risk profiles and the need for multiple adjustments. It did not believe that systematic risk has increased in RIIO-3 compared to RIIO-2 and emphasises that non-systematic risks should not be reflected in beta estimates. It argued that our position is contradictory—claiming many RIIO-3 risks are non-systematic, while also justifying the use of European comparators based on systematic risk. It concluded that the evidence supporting the use of European comparators is insufficient and puts forward several proposals for lowering the beta.

3.51 The consumer group is right to note that, during RIIO-2, we advised caution regarding the use of European comparators. However, we view the regulatory framework as an evolving process. Where compelling evidence supports a change, we consider it is appropriate to make that change. Given the shift in risk profile from RIIO-2 to RIIO-3, and the limited representation of energy, particularly gas, companies in our dataset, we consider including European comparators is a justified and appropriate response.

3.52 Oxera highlighted evidence of higher gas betas in the US. In contrast, NERA questioned the beta comparator set, challenging the inclusion of National Grid and water companies and the exclusion of Hera, an Italian multi-utility company.

3.53 We do not consider the US gas regulatory system as a valid comparator for several reasons. US utility regulation tends to be on an ex post basis, meaning

there is greater risk for US utilities in recovering costs incurred. US regulation is conducted on a state-by-state basis, which complicates aggregated comparisons. Even when aggregated, S&P (the financial information and analytics company) analysis shows that US utilities often earn below their authorised returns. Finally, cross-border comparisons of regulatory regimes are inherently complex and can be misleading. However, because the Spanish and Italian regulatory frameworks more closely resemble the GB regime, we considered it appropriate to include companies from those countries.

3.54 We do not assign disproportionate weight to National Grid's beta evidence, as we consider all nine comparators equally in our analysis. We consider National Grid a relevant comparator, given that most of its operations are subject to regulatory oversight. We see continued value in using UK water company betas as supporting evidence, particularly in the absence of pure-play GB energy network comparators. These companies operate within the same GB regulatory framework, and investors in UK utilities are likely to assess them in relation to energy networks. Moreover, some energy network companies themselves reference the allowed returns in the UK water sector, reinforcing the relevance of water company betas in this context. We considered Hera as a potential beta comparator. However, analysis by Frontier Economics indicated that only 30–40% of its revenues are derived from regulated energy activities. Given this limited exposure, we decided not to include Hera in our comparator set. While we acknowledge that electricity networks are facing elevated capital expenditure during RIIO-3 we do not consider these to be systematic risks.

Step-2 Checking our Step-1 estimate is neither excessive nor insufficient

3.55 In our Draft Determinations we outlined a summary of cross-check evidence. Our consultation position was that this evidence supports the use of the midpoint from our Step-1 CAPM calculation.

Final Determinations

3.56 We have decided our cross-check evidence supports the use of the midpoint from our Step-1 CAPM calculation. This is consistent with the position we proposed in our Draft Determinations.

3.57 We have decided to apply a set of cross-checks to validate the CAPM-derived cost of equity. Specifically, we have used: Transaction Market Asset Ratios (MARs); Traded MARs; and Infrastructure Funds Implied Internal Rate of Return (IRR). These cross-checks provide a broader market-based perspective and help ensure

the robustness of our estimates. The results of these cross-checks are presented in Table 12 below.

Table 12: Cross checks, cost of equity range and proposed cost of equity, CPIH-real

Cross-check	Cost of equity
MAR (transaction) implied cost of equity	4.5%
MAR (traded) implied cost of equity	5.1%
Infrastructure Fund implied IRR	7.0%
Our recommended cost of equity estimate range	4.91% - 6.95%
Our proposed cost of equity (55%/60% gearing)	5.70% / 6.12%

Source: Ofgem analysis

3.58 We have decided to retain our Draft Determination position and maintain a 3% dividend yield assumption and a 5% equity issuance cost allowance.

3.59 We have decided not to apply any specific gearing thresholds above or below notional gearing in relation to either equity issuance or additional dividends / returns on capital.

Stakeholder responses and rationale

Responses to FQ12: Do you agree with the conclusion we have drawn from our chosen cross-checks?

3.60 One consumer group made several recommendations. For transaction MARs, it advised that we should derive the cost of equity from the available data. It also suggested that our offshore transmission owner (OFTO) analysis be adjusted to account for the difference in gearing between OFTO projects and notional companies. Additionally, it recommended that, in the Infrastructure Fund IRR cross-check, any inferred cost of equity should be taken from the lower end of the range, as the funds are not risk-adjusted.

3.61 In line with the consumer group's recommendation, we have derived a cost of equity using transaction MARs. Regarding its OFTO cross check recommendation, we have decided to discontinue using this cross check for the reasons outlined below. As for the infrastructure fund implied IRR cross check, it is important that our cross checks remain both relevant and practical. We also aim to keep them simple and objective; applying a risk adjustment to each infrastructure fund or relying solely on the lower end of the IRR range would undermine this approach by adding complexity and subjectivity.

3.62 All network companies disagreed with the conclusions we drew from our selected cross-checks. They raised concerns about the appropriateness of the cross-checks used and proposed additional alternatives. Several consultant reports were cited in support of their positions, including work from Frontier Economics, Oxera, KPMG, and Kairos.[32] [33] [34] [35] [36] [37] [38]

3.63 The ENA criticised us for not adequately engaging in discussions around equity cross-checks, stating that our analysis is both incomplete and inconsistent. It referenced analysis conducted by Frontier Economics to support its position.

3.64 We consider the cross-check analysis presented in this chapter is both complete and consistent with previous price control iterations. We address various Frontier comments throughout the following paragraphs.

3.65 Hybrid Bond Cross-Check: Frontier Economics responded to our concerns regarding the hybrid bond cross-check. On the issue of spread variability, it highlighted that 80% of observed spreads fell within a relatively narrow band of 100 to 213 bps, which it described as a compelling feature. Regarding the equity-like characteristics of hybrid bonds, Frontier pointed to the ability to defer coupon payments and their subordinated status relative to senior debt. It has since updated its analysis and now infer a CPIH-real equity return of 6.5%.

3.66 We continue to have concerns with this analysis, particularly due to the variability in spreads, which Frontier also highlights—80% of observed spreads fall within what we consider a broad range of 100 to 213 bps. Additionally, as noted by the CMA in their PR24 Provisional Determinations, the implied cost of equity from Frontier's hybrid bond analysis is highly sensitive to assumptions around default risk pricing and the degree of equity-likeness attributed to the hybrid bond. These sensitivities result in a wide range of outcomes for the implied cost of equity. We

[32] Frontier Economics, Cross-Check Standards of Evidence for ENA and FEN (August 2025)
[33] Frontier Economics, Updated Cost of Equity Cross-Check Evidence for FEN (August 2025)
[34] Frontier Economic, Updated Cost of Equity Cross-Check Evidence for ENA (August 2025),
[35] Oxera, RIIO-3 Draft Determinations - CAPM parameters and debt-based cross-checks for ENA (August 2025)
[36] Oxera, RIIO-GD&T3 cost of equity and debt premium cross-check for ENA (August 2025)
[37] KPMG, Inference analysis as a cross-check on allowed returns at GD&T3 for FEN (August 2025)
[38] Kairos, Cost of Equity for RIIO-2: Gas vs Electricity and MFM Cross-Check (August 2025)

agree with the CMA that this does not serve as a useful cross-check for determining a point estimate of the cost of equity.[39]

3.67 Infrastructure Fund IRR Cross-Check: Frontier Economics analysed our Infrastructure Fund implied equity IRR cross-check and criticised us for not engaging with its implications or clarifying how it influenced its overall assessment. Frontier argued that the cross-check result lies significantly above the upper bound of the Step 1 CAPM range, suggesting a notable upward shift in implied equity returns since RIIO-2. Based on their updated analysis from March 2025, Frontier estimate the average implied equity IRR at 11.8% in nominal terms, or 9.6% in CPIH-real terms.

3.68 We have decided to update our Infrastructure Fund implied equity IRR cross-check. One key change is the deduction of each fund's Ongoing Charges Ratio (OCR) when calculating the implied IRR, to better reflect the net return available to investors. The OCR represents the annual cost of operating an investment fund and is a critical factor in assessing investor returns. Following this adjustment, the average implied real IRR from our analysis is 7.0%, which is close to the upper end of our cost of equity range. In considering how this influences our overall assessment, it is important to note that the purpose of cross-checks is to ensure our CAPM-based cost of equity estimate is appropriately calibrated—neither too low nor too high. Cross checks are not applied mechanically; for example, averaging the cross-check results to set the CAPM estimate would undermine the rationale for conducting a CAPM analysis in the first place. However, if our CAPM estimate were to fall outside the range indicated by the cross-checks—or sit at the extreme ends—we would likely revisit the underlying variables in our CAPM calculation. Please see the updated analysis in Table 13 below.

Table 13: Infrastructure Fund implied IRR

	Share price (p)	**Fund NAV (p)**	**Price /NAV**	**Discount rate**	**OCR**	**Implied IRR[40]**	**Real implied IRR[41]**
BBGI Global Infrastructure	124.6	142.7	0.87	7.6%	0.92%	7.7%	5.4%

[39] CMA, Water PR24 price redeterminations, Volume 4, Chapters 7-10, paragraph 7.503
[40] Implied IRR = (Discount rate - ongoing charges ratio) / (P/NAV)
[41] Deflated by an inflation assumption of 2.1%

	Share price (p)	Fund NAV (p)	Price /NAV	Discount rate	OCR	Implied IRR[40]	Real implied IRR[41]
Greencoat Renewables(€)	82.3	110.5	0.74	7.2%	1.18%	8.1%	5.9%
HICL Infrastructure	118.8	156.5	0.76	8.1%	1.10%	9.2%	7.0%
Bluefield Solar	94.2	126.0	0.75	8.0%	1.01%	9.4%	7.1%
International Public Partnerships	121.2	144.7	0.84	9.0%	1.14%	9.4%	7.1%
Greencoat UK Wind	127.7	151.7	0.84	9.0%	0.95%	9.5%	7.3%
Foresight Solar Fund	77.0	112.3	0.69	7.9%	1.17%	9.8%	7.5%
GCP Infrastructure Fund	70.8	105.2	0.67	8.0%	1.21%	10.0%	7.8%
The Renewables Infrastructure Fund	85.8	115.9	0.74	8.6%	1.04%	10.2%	7.9%
						Average	**7.0%**

Source: Ofgem analysis and company websites.

MARs

3.69 Frontier welcomed our decision to place greater emphasis on traded MARs over transaction MARs. However, it noted that traded MARs have significant limitations, being time-sensitive and influenced by broader market dynamics. Frontier also raised concerns about analyses that rely on stylised assumptions projected into perpetuity—such as long-term Regulatory Capital Value (RCV) growth and outperformance. In its updated analysis, Frontier presented a range of implied equity returns from 5.08% to 8.80%, based on RCV growth assumptions of 2% to 4% and outperformance ranging from 0% to 5%.

3.70 We have also revised our MAR analysis to present implied cost of equity estimates from both transaction and traded MARs, without placing undue emphasis on either. To improve clarity and robustness, we have removed any reliance on stylised perpetuity assumptions. We have, however, assumed 1.0% operational outperformance which raises the implied cost of equity as history shows us that

networks typically outperform. The updated analysis results in an implied cost of equity of 4.5% from transaction MARs and 5.1% from traded MARs - both of which sit below the lower end of our cost of equity range. As noted previously, the purpose of cross-checks is to ensure our CAPM-based cost of equity estimate is appropriately calibrated - neither too low nor too high. Please see the tables below for our updated MAR analysis.

3.71 In 2024, several major transactions were announced that continue to demonstrate acquisitions being made at premiums to regulated asset bases (RABs). These substantial MAR premiums are difficult to justify without assuming either higher-than-required returns or sustained and significant outperformance. For example, in January 2024, Pennon Group plc announced its acquisition of Sutton and East Surrey (SES) Water, with the transaction reflecting a premium of approximately 6% to SES Water's RCV, as noted in Ofwat's PR24 Final Determinations. In July, Macquarie Asset Management exercised its option to acquire the remaining 20% equity interest in National Gas from National Grid. Then in August, Iberdrola agreed to acquire 88% of Electricity North West (ENWL). UBS analysis indicates that these deals involved premiums of around 25% and 60% respectively to the companies' regulated asset bases. The average implied cost of equity from this analysis was 4.49% and can be seen in Table 14.

Table 14: Transaction MARs implied cost of equity

Transaction MARs	**SES Water**	**National Gas**	**ENWL**	**Reference**
MAR (at transaction date)	106%	125%	160%	A
Gearing (Ofwat PR24 / Ofgem RIIO-3)	55%	60%	55%	B
Debt value	100%	100%	100%	C
Equity market value	51%	65%	105%	D = A-(B*C)
Notional value of equity	45%	40%	45%	E=(1-B)
Equity MAR	113%	163%	233%	F=D/E
Allowed return on equity (Ofwat PR24 / Ofgem ED2)	5.10%	6.04%	5.23%	G
Implied cost of equity (on-target)	**4.50%**	**3.72%**	**2.24%**	H=G/F
Debt outperformance	0.0%	0.0%	0.0%	I

Transaction MARs	SES Water	National Gas	ENWL	Reference
Operational outperformance	1.0%	1.0%	1.0%	J
Implied cost of equity (with outperformance)	**5.50%**	**4.72%**	**3.24%**	K=(H+I+J)
Average of above	**4.49%**			

Source: Ofgem analysis

3.72 For traded MARs, we reference the MAR premia of the UK listed water sector as of August 2025. At that time, the average MAR premium stood at 11%, closely aligned with the sector's long-run average of 10%. Based on this analysis, the average implied cost of equity was 5.12%, as shown in Table 15.

Table 15: Traded MARs

Traded MARs	United Utils	Severn Trent	Pennon	Reference
MAR (August 2025)	110%	117%	106%	A
Gearing (PR24)	55%	55%	55%	B
Debt value	100%	100%	100%	C
Equity market value	55%	62%	51%	D=A-(B*C)
Notional value of equity	45%	45%	45%	E=(1-B)
Equity MAR	122%	138%	113%	F=D/E
Allowed return on equity (PR24)	5.10%	5.10%	5.10%	G
Implied cost of equity (target)	**4.17%**	**3.70%**	**4.50%**	H=(G/F)
Debt outperformance	0.0%	0.0%	0.0%	I
Operational outperformance	1.0%	1.0%	1.0%	J
Implied cost of equity (with outperformance)	**5.17%**	**4.70%**	**5.50%**	K=(H+I+J)
Average of above	**5.12%**			

Source: Ofgem analysis

OFTO Bid Cross-Check

3.73 Frontier argued that we provided no justification for the time periods selected or context for the data used in the OFTO bid cross-check. It noted that, because the

data is confidential, stakeholders have no visibility over the underlying assumptions or reasoning. Frontier also questioned the relevance of OFTOs, pointing out that these projects do not involve construction activities and do not operate under a RAB model.

3.74 Following a reassessment of our Draft Determinations and a review of responses, we have decided to discontinue the use of OFTO bid-implied returns as a cross-check. This decision is based on two factors: OFTO projects differ materially from network projects, particularly in their risk profile. They carry no construction risk and typically operate with gearing levels around 90%, compared to 55–60% for the notional entity; the confidential nature of OFTO bid data limits our ability to provide the level of transparency we consider necessary. Given these considerations, we no longer consider OFTO bid-implied returns as a suitable or robust cross-check for assessing the cost of equity.

Sizewell C IRR

3.75 Frontier noted that Centrica estimates its project IRR for Sizewell C to be over 12% post-tax nominal in a scenario with 'moderate' cost and schedule outcomes. Even in cases of 'severe' cost overruns and delivery delays, Centrica still expects a post-tax nominal return above 10%. Frontier argued that, as Sizewell C is a RAB-financed construction project with a low-risk, regulated revenue stream, it should be considered as a relevant cross-check.

3.76 We do not consider Sizewell C to be a valid cross-check to our cost of equity estimate:

(1) Network companies argue that Sizewell C's allowed cost of equity (reported by Centrica as 10.8% real) demonstrates that our 5.7% real allowance is too low. However, this return applies only to the 12–15-year construction phase - the riskiest part of the project - and excludes the operational phase when the plant generates electricity. In contrast, network companies both build and operate their assets, and our allowed cost of equity covers the entire lifecycle. For this reason, we do not consider Sizewell C a valid comparator.

(2) Sizewell C is a single, large-scale nuclear construction project with few suitable comparators. Characteristics such as the high incidence of cost overruns in nuclear projects and investor hesitancy toward nuclear infrastructure likely influenced the government's approach. Moody's Ratings credit opinion on Sizewell C noted its credit quality is constrained by the significant construction risk and highlighted other credit

considerations including the reliance on certain key contractors, the exposure to single site and single technology, a leveraged profile and weak cash flow-based metrics. These factors make the project fundamentally different from the regulated energy networks under our assessment.

Long-Term Profitability Benchmarking

3.77 With the availability of 2024 data, Frontier has updated its analysis of long-term profitability benchmarking. It argues that criticisms related to gearing differences and imperfect risk comparability apply equally to other cross-checks. Frontier Economics' updated evidence shows a real return range of 5.6% to 17.5%, with a median of 8.8%.

3.78 Our key concerns with long-term profitability benchmarking as a cross-check centre on the difficulty of ensuring meaningful comparability between regulated and non-regulated companies, as well as the limitations and inconsistencies in accounting metrics used across firms. Additionally, this cross-check produces a wide range of outcomes for the implied cost of equity. Given these factors, we do not consider it a reliable or useful tool for determining a point estimate of the cost of equity.

US Returns

3.79 NGET referenced previous analysis by Frontier Economics on authorised returns for comparable US utilities, which were found to be in the range of 9% to 10%. Frontier Economics acknowledged that while there are differences between UK and US regulatory regimes, it is not clear whether risk is higher or lower in either market. It argued that investors are likely to be generalists rather than utility specialists, making headline return figures important in their own right.

3.80 Frontier Economics suggests that authorised returns for comparable US utilities - typically in the 9% to 10% nominal range - should be considered as a cross-check. However, we do not consider this a valid comparator for several reasons: US allowed returns are largely ex post authorised returns, meaning US utilities bear an element of inflation risk that UK regulated companies do not; US regulation is conducted on a state-by-state basis, making aggregated comparisons problematic; even when aggregated, S&P analysis shows that US utilities often earn less than their authorised returns. Between 2020 and 2024, the average achieved nominal return was 9.1% for electricity utilities and 8.3% for gas utilities—equating to real returns of around 4.0% (US inflation averaged around 4.4% during 2020-2024) compared to RIIO-2's real CoE allowance of

4.55%; finally, cross-border comparisons of regulatory regimes are inherently complex and can be misleading. In 2024 Iberdrola achieved nominal returns of just 4.9% in Maine and between 5.9% and 7.1% in New York, compared to allowed returns of 9.35% and 9.2%, respectively. National Grid's electricity and gas businesses in Massachusetts and New York (Niagara Mohawk) delivered nominal returns ranging from 4.64% to 8.6% in 2024, despite allowed returns between 9.0% and 9.7%. Given these considerations, we do not view US utility returns as a reliable or appropriate cross-check for assessing the cost of equity in the UK context.

European Returns

3.81 In the same analysis, Frontier Economics found that the equity premium over the RFR—adjusted for consistent gearing—is lower in the UK than in many comparable European jurisdictions.

3.82 In response, we have seen RBC Capital Markets (the global investment bank) analysis indicating that allowed real returns for Italian utilities are in the 5.9–6.0% range, while Spanish utilities are allowed 4.9–5.4%. These jurisdictions were among those recommended by network companies as beta comparators, and their allowed returns are comparable to—or below—our proposed RIIO-3 cost of equity. As with other international comparisons, we emphasise that cross-border regulatory benchmarking is inherently complex and should be approached with caution. Nonetheless, the Spanish and Italian regulatory frameworks share notable similarities with the GB regime, which is why we have consider including Spanish and Italian energy companies in our beta dataset to be appropriate.

3.83 Asset risk premium to debt risk premium (ARP-DRP) cross check: Oxera pointed out that our unlevered cost of equity is lower than the cost of new debt, which it argues goes against established financial principles. Its updated ARP-DRP analysis further concludes that our equity allowance may be set too low.

3.84 We have broader concerns with the ARP-DRP approach, particularly its inability to definitively determine or 'back-solve' a required return on equity. The assumption that real equity returns do not move one-for-one with changes in the RFR is a well-established principle in UK regulation. This relationship is unlikely to be stable or linear, contrary to Oxera's presentation. In its PR24 Provisional Determinations, the CMA rejected Oxera's interpolation to 100% gearing to derive an implied ARP, as well as the notion that the ARP-DRP framework can serve as a strict lower bound for the cost of equity. The CMA emphasised that estimating the underlying debt risk premium—comparable to the equity risk premium—is subject

to considerable uncertainty. It concluded that Oxera's ARP-DRP analysis does not provide a reliable basis for setting a lower bound on the allowed return on equity.[42]

Debt Inference cross-check

3.85 KPMG's analysis for Future Energy Networks (FEN) focuses on inferring the cost of equity from market pricing of debt. They highlight the higher cost of debt allowances for gas networks and argue that both the cost of equity and cost of debt should reflect the sector's evolving and comparatively higher risk profile.

3.86 We have several concerns with KPMG's analysis. Its estimate of the cost of new debt includes a 45bps gas-specific premium derived by NERA, which is higher than the premium used by us. KPMG infers the cost of equity by considering both the elasticity of National Grid and the gas-specific debt risk premium. However, National Grid differs significantly from gas distribution companies in terms of, for example, areas of business and gearing levels, making direct comparisons problematic. In its work on the water sector KPMG identified differing elasticities between United Utilities and Severn Trent, companies in the same sector, highlighting the variability in such estimates. KPMG also notes a wide range of correlation between National Grid's equity and debt returns, varying from 0.41 to over 0.60 depending on the time period analysed. Importantly, in its PR24 Provisional Determinations, the CMA chose not to rely on KPMG's inference analysis when selecting a point estimate for the cost of equity. Given these factors, we do not consider debt inference analysis to be a robust or appropriate cross-check for assessing the cost of equity in the UK regulatory context.

MFM Cross-Check on CAPM

3.87 Kairos Economics carried out a multi-factor model (MFM) cross-check against the CAPM, finding that the MFM produced a cost of equity estimate around 30 bps (0.3%) higher than CAPM. It argued this difference indicates that CAPM may underestimate the cost of equity for gas networks relative to electricity networks, and more broadly, may fail to fully capture the systematic risk faced by regulated UK utilities.

3.88 We have reservations about using MFMs as a cross-check on CAPM. As Kairos Economics notes, factor return data is not readily available for European comparators, resulting in the exclusion of five out of nine relevant companies from the analysis. Moreover, we are not aware of any theoretical foundation

[42] CMA, Water PR24 price redeterminations, Volume 4, Chapters 7-10, paragraph 7.490

supporting the application of the factor model to regulated markets, which differ materially from competitive markets. Consequently, the investment and profitability factors central to the factor return model do not clearly apply in this context. Kairos Economics also cites only one academic paper using UK data, which requires peer review. The CMA's PR24 Provisional Determinations reached similar conclusions. In light of these limitations, we do not consider there to be a robust rationale for placing weight on MFMs as a cross-check to the CAPM-derived cost of equity.

Vallorii on CAPM

3.89 NGET referenced a paper by Vallorii that highlights limitations in CAPM estimations of beta and returns.

3.90 While a range of alternative models to the CAPM exist, none has seriously challenged its position as the dominant framework within UK economic regulation. The CAPM continues to be widely used by financial practitioners, largely due to its simplicity and transparency—it relies on just three inputs, each of which can be derived with relative ease from publicly available data. Most stakeholders support the continued use of the CAPM, though there is ongoing debate around how its inputs are calculated. As Valorii notes, the CAPM is not used in isolation; its cost of equity estimates are routinely cross-checked against market-based evidence. There is healthy discussion among stakeholders regarding which cross-checks are most appropriate, and both the input methodologies and cross-checking practices continue to evolve to improve the robustness of outcomes. These enhancements help address the limitations that Valorii raises. While Valorii suggests the use of multi-factor models, we have already discussed their drawbacks. As Valorii also acknowledges, it is essential that the approach remains simple and transparent principles we have consistently upheld.

Responses to FQ13: Do you agree with our treatment of risks to the ET and Gas sectors as non-systematic?

3.91 One consumer group agreed that risks in the ET and Gas sectors are non-systematic. However, it noted that our inclusion of European company betas implies that some of these risks are being treated as systematic. It considered this contradictory, arguing that changes in risk cannot simultaneously be classified as both systematic and non-systematic.

3.92 In response to the consumer group, we consider estimating an appropriate beta is inherently challenging due to the absence of 'pure play' listed GB energy networks that can serve as direct comparators. While European utility companies

operate in a similar sector and are likely exposed to comparable risks, they are subject to different regulatory frameworks. This trade-off mirrors the approach taken when using GB water companies as comparators—where the sector differs, but the regulatory regime is closely aligned. Despite these limitations, we find a net benefit in including European utilities in our comparator set, particularly as it allows us to incorporate gas energy network companies. Our intention is not to make assumptions about systematic risk, but rather to evolve our comparator set to be as relevant and representative as possible.

3.93 The network companies challenged the classification of certain risks to the ET and gas sectors as non-systematic. For electricity networks, they cited elevated capital expenditure, the precedent set by RIIO-1's 'aiming up' approach, and the importance of maintaining investor confidence. For gas networks, concerns centred on asset stranding risk, observed beta differences compared to the electricity sector, higher debt costs, and commentary from credit rating agencies.

3.94 We agree that the ET companies face substantial debt and equity financing needs throughout RIIO-3 and beyond. The regulatory framework is designed to strongly support and incentivise the delivery of necessary investment, ensuring the sector remains attractive to investors. We consider that the beta estimate will appropriately capture any changes in risk between RIIO-2 and RIIO-3. Market evidence suggests robust investor appetite: Iberdrola's €5 billion equity raise in July 2025 (after the publication of our Draft Determinations) was 3.8 times oversubscribed, and analyst responses to our Draft Determinations were generally positive. Major players such as SSE, National Grid, and Iberdrola continue to receive positive recommendations from the analyst community. We have no evidence to aim up because of the risks of underinvestment.

3.95 The UKRN recommends considering five key factors when selecting a point estimate within the CoE range. After evaluating each, we remain confident that the mid-point of our CoE range remains the most appropriate choice rather than aiming up or aiming down.

- Market-Based Cross Checks: External benchmarks suggest a CoE range of 4.5-7.0%, which aligns well with our proposed allowance range of 5.70-6.12%, supporting the mid-point selection
- Potential Welfare Impact of Underinvestment: The Network Asset Risk Metric (NARM) framework provides a structured approach to assessing and managing asset risk. Investor sentiment remains strong, evidenced by Iberdrola's €5bn equity raise in July, which was 3.8x oversubscribed. Additionally, SSE,

National Grid, and Iberdrola continue to receive broadly positive analyst recommendations

- Asymmetries in Incentive Structures: Since companies have historically exceeded their allowed returns, there is no precedent of underperformance that would discourage investors or necessitate an upward adjustment
- Asymmetries in CAPM Parameters: Our CAPM inputs are robust. The inclusion of European energy firms in the beta estimate, a TMR that exceeds equity market cross-checks, and our proposed allowances sitting near the mid-point of the 4.5-7.0% cross-check range all reinforce confidence in our parameter choices
- Financeability: Our latest analysis confirms that licensees are financially resilient, with the ability to maintain appropriate credit ratings under the proposed CoE assumptions

3.96 We agree with the CMA's view in its PR24 Provisional Determinations that setting the cost of equity above the mid-point of the estimate range requires careful consideration and should not be the default approach.[43] The CMA noted that, given the unique circumstances of the water sector price control, a modest degree of aiming up on the cost of equity could ultimately benefit customers. It also observed that Ofwat considered investor sentiment towards the water sector to be low. This contrasts with the energy sector, where we have seen positive market responses to equity raises by SSE plc and Iberdrola, strong share price performance among listed energy companies, and generally favourable analyst recommendations. This supports our decision to select the mid-points of our cost of equity ranges as the point estimates for our cost of equity allowances.

3.97 We do not consider any of the additional risks identified in the gas sector to be systematic in nature, nor do we consider they warrant compensation from consumers to investors. While a debt premium for gas over electricity has emerged—and is reflected in our cost of debt allowance—the evidence on asset betas points in the opposite direction. The two-year average asset beta for gas companies in our comparator set is lower than that of both the electricity and water sectors. Notably, Moody's July 2025 commentary on gas networks highlighted our decisions as generally supportive of network company activities,

[43] CMA, Water PR24 price redeterminations, Volume 4, Chapters 7-10, paragraph 7.550-7.552

reaffirming their view of us as a provider of transparent and predictable regulation.

Responses to FQ14: Do you agree with our proposed dividend allowance policies for the notional gas and electricity companies?

3.98 Gas companies argued for higher dividend allowances, primarily on the basis that, with muted RAV growth, dividends become the sole source of return for equity investors. As such, they contended that the dividend yield should closely align with the cost of equity. Additional support for this position was drawn from the comparatively higher dividend yields observed among gas companies across Europe. Gas companies also argued that the return of capital policy should have a zero percent threshold, rather than the 5% proposed. They suggested this change would help avoid trapped equity and reduce lumpiness in the return of capital.

3.99 During RIIO-3, there may be downward pressure on gearing within the gas sector. However, as the steps toward the energy transition remain undefined, it would be premature to adjust the allowed notional company dividend yield at this stage. In our Draft Determinations, we proposed allowing additional dividends or return on capital if gearing reached a certain threshold. Following company feedback, we have decided not to set a gearing threshold for this mechanism, thereby avoiding the risk of trapped capital or uneven distribution of additional dividends / returns on capital. Our final determination is to maintain a 3% notional company dividend yield assumption.

3.100 Electricity companies also argued for higher dividend allowances, with their main arguments centred on market benchmarks and investor expectations.

3.101 As stated in our Draft Determinations, we see significant value in the expected growth of the RAV—and consequently dividends—in the ET sector during RIIO-3. Both RAV and dividend growth could comfortably exceed 10% on a compound annual basis. Retained earnings will be essential to support this expansion, and a 3% dividend yield alongside such strong dividend growth presents an attractive proposition for investors.

3.102 Therefore, we have decided to maintain a 3% notional company dividend yield assumption.

Responses to FQ15: Do you agree with our proposal not to apply the flat WACC approach?

3.103 One consumer group expressed support, noting that removing the flat WACC approach helped to avoid distortions in the CAPM model.

3.104 The gas companies responded that this approach was not relevant to their circumstances.

3.105 The electricity companies did not agree with our proposal not to apply the flat WACC approach. Their main rationale for maintaining a flat WACC approach was to ensure regulatory consistency and preserve investability, rather than factors such as debt structures or sector-specific considerations. They also referred to our position that the gas and electricity sectors have similar risk levels, arguing that the WACC should therefore be the same for both sectors. NPg additionally argued for a longer transitional period to adjust to a lower level of gearing.

3.106 During RIIO-2, we adjusted the cost of equity for companies with different notional gearing levels using the original Modigliani–Miller theorem, which asserts that a firm's overall cost of capital is unaffected by its capital structure. In practice, this meant back solving the cost of equity for lower geared companies on the assumption they shared the same cost of capital as higher geared companies. The original Modigliani–Miller theorem was later revised by its authors, who concluded that the cost of capital actually declines as leverage increases. Taken to its logical extreme, this would imply that firms should be entirely debt-financed. In reality, companies maintain a mix of debt and equity because excessive leverage raises the risk of financial distress. For this reason, we have decided to discontinue the 'flat WACC' methodology.

3.107 The gearing levels remain unchanged in RIIO-3 following the removal of the flat WACC approach; therefore, we see no justification for an adjustment period.

Responses to FQ16: Do you agree that our proposed package for gas and electricity companies is investable?

3.108 One consumer group considers the package to be investable. However, it does not support introducing the term 'investability' alongside 'financeability', arguing that if companies can finance their activities—including through equity issuance—they are, by definition, investable. It points to real-world MAR evidence to show the sector remains highly attractive to investors. It disagrees with network companies' claims that risks are higher under RIIO-3, viewing the growth in ET as an investment opportunity. It also believes that all costs will be recovered in the gas sector and that gas assets will not be stranded. For ET, it argues the package includes multiple protections enabling low-risk investment. It also considers the 5% equity issuance allowance to be overly generous.

3.109 We agree with many of the points raised by the consumer group. Fundamentally, if a regulatory framework is investable, it will attract investors and all our previous price controls have met this standard. The key is ensuring the right balance between risk and reward. Regarding our equity issuance allowance of 5%, we noted in our Draft Determinations that National Grid's equity issuances in 2010 and 2024 incurred direct costs of around 3.0%. Oxera's analysis showed that the 25th percentile of indirect issuance costs for UK regulated companies ranged from 1.7% to 2.6%. In this context, a total allowance (i.e. direct and indirect costs) of 5% is reasonable.

3.110 The network companies do not consider the proposed package to be investable. They commonly argue that the cost of equity is set too low. The network companies also believe the allowed dividend yield is insufficient. In addition, the ENA argues that there is a lack of detail on incentives and totex allowances are unsupportive. Gas companies have highlighted that the return on capital threshold should be 0%, while electricity companies contend that further changes are needed to enable a pathway to nominal returns of 9–10%.

3.111 We have demonstrated that our cost of equity allowances are supported by cross-check evidence, as outlined in our response to FQ12. Similarly, we have explained why the allowed dividend yields are appropriate in our response to FQ14. Our Final Determination is to set the return on capital/additional dividend threshold at 0%. As a regulator, we do not target specific nominal returns; instead, our approach is to set real cost of equity allowances that are sufficient to attract and retain equity capital, while also ensuring fairness for existing and future consumers.

3.112 The incentive package for electricity transmission operators under RIIO-ET3 is intentionally designed to offer rewards for successfully meeting the scheme's significant delivery challenges. For instance, operators can earn high rewards for the early or timely completion of major reinforcement projects. There are also upside-only incentives for those who innovate in infrastructure delivery and collaborate effectively with the system operator. Additionally, RIIO-ET3 proposes a modified Totex Incentive Mechanism sharing rate, which offers enhanced protection against excessive cost increases.

Step-3 Expected versus allowed returns

3.113 In our Draft Determinations our working assumption was that there is risk symmetry within the aggregate balance of the whole price control, and therefore a Step-3 adjustment was not required at this stage.

Final Determinations

3.114 We have decided to retain our Draft Determinations position that a Step-3 adjustment is not required.

Stakeholer responses and rationale

Responses to FQ17: Do you agree with our working assumption that there is risk symmetry within the aggregate balance of the whole price control?

3.115 One consumer group viewed the balance of risk as asymmetric in favour of network companies. This conclusion is based on evidence of consistent and systematic outperformance under previous price controls, recent changes that shift more risk from companies to consumers, and confidence that we would intervene if an unexpected event were to harm companies.

3.116 We agree with the consumer group's conclusion that, in aggregate, network companies have typically outperformed under previous price controls. We are committed to maintaining a balanced approach that serves both investors and consumers. Following RIIO-1, revenue adjustment mechanisms were introduced to enhance this balance in RIIO-2, and in RIIO-3, we are implementing a semi-nominal WACC allowance. Such measures reflect our ongoing efforts to ensure that the regulatory framework remains fair and proportionate to both investors and consumers.

3.117 The network companies did not agree that risk is symmetrically distributed across the entire price control. They point to several sources of asymmetric downside risk, including cost assessment methodologies, the potential for asset stranding, output delivery incentives (ODIs), ongoing efficiency requirements in totex, real price effects (RPEs), and what they describe as unworkable re-openers. The ENA highlights the same risk asymmetries identified by the network companies.

3.118 Frontier Economics, on behalf of NGET, presented a holistic framework for assessing investability. It highlighted increased competition for capital and stresses the importance of cross-check evidence. Frontier Economics also drew comparisons with utility sectors in other countries regarding allowed returns. In relation to the broader package, it identified several risks: our proposed RPEs may not reflect NGET's actual input cost experience; there is significant spend at risk for inflight projects; and there is potential for an extreme overspend scenario concerning one ASTI project.

3.119 We agree with Frontier Economics on the importance of cross-checks. Validating our Step-1 cost of equity estimates through cross-checks ensures they are neither excessive nor insufficient, providing a broader market-based perspective

and reinforcing the robustness of our approach. This forms the backbone of Step-2 in our process for setting allowances. We have addressed international utility sector comparisons in our response to FQ12, and our beta comparator set now includes energy companies from Spain and Italy.

4. WACC allowance

Purpose: The WACC allowance remunerates debt and equity investors for their investment in network services.

Benefits: Accurate remuneration will secure network investment during RIIO-3 and help keep consumer charges in line with efficient costs.

Final Determinations summary

4.1 Our Final Determination on the baseline return on capital is summarised in Table 16 and reflects the decisions made in other chapters. We present the nominal and real WACC allowances for transparency.

Table 16: Final Determinations on the RIIO-3 baseline allowed return on capital (average for five years end 31 March 2031, CPIH real)

Component	GD & GT	NGET	SPT	SHET
Notional Gearing	60%	55%	55%	55%
Cost of equity allowance (real)	6.12%	5.70%	5.70%	5.70%
Cost of debt allowance (semi-nominal)	4.66%	5.31%	5.58%	5.76%
WACC allowance (semi-nominal)	5.24%	5.49%	5.63%	5.73%
WACC allowance (real)	4.34%	4.42%	4.56%	4.66%
WACC allowance (nominal)	6.52%	6.60%	6.75%	6.85%

Source: Ofgem analysis (values may not sum due to rounding)

4.2 In RIIO-3 the approach to the allowed return on debt is foundationally similar to RIIO-2. However, there are some proposed methodological changes, as set out in Chapter 2. These include a benchmark change for the new debt assumption, a reduction in the ILD assumption for ET, a benchmark adjustment for the new debt cost assumption for gas and a reduction in additional borrowing allowances for ET.

4.3 The semi-nominal WACC allowance is calculated using the real cost of equity allowance and the semi-nominal cost of debt allowance. The semi-nominal cost of debt allowance is calculated using the proportions of ILD and fixed rate debt for each sector. The ILD proportion for the gas sectors is 30% and for ET is 10%. The semi-nominal WACC is used to calculate the cash part of the return that investors receive. However, this does not include the effect of inflation indexation to the RAV, which also contributes to the total returns investors earn.

4.4 The real WACC allowance is calculated using the real cost of equity allowance and a real cost of debt allowance on a like-for-like basis with RIIO-2. This allows comparability between RIIO-3 and RIIO-2.

4.5 The nominal WACC allowance is calculated using a nominal cost of equity and a nominal cost of debt. This shows the total return to investors considering both the cash component and the inflation indexation of RAV.

4.6 Starting in 2025 the OBR began publishing CPIH projections, so we now use this as the inflation assumption throughout our calculations to express them in CPIH terms.

4.7 In line with UKRN guidance, we set notional gearing based on our assessment of the balance of risks facing the regulated company and a range of relevant evidence, rather than solely on actual company gearing levels. For RIIO-3, we propose maintaining the notional gearing levels used in RIIO-2: 55% for ET and 60% for the gas sectors. We also propose that the notional capital structure remains constant throughout the price control period.

5. Debt Financeability

Purpose: Checking that all components of our Final Determinations, when taken together, allow an efficient operator assuming the notional capital structure to generate cashflows sufficient to meet its debt financing needs.

Benefits: Enabling continued investment in networks, facilitating stable and efficient energy supply systems that deliver long-term benefits and cost-effectiveness for consumers.

Final Determinations summary

Financeability parameter	Final Determination	Draft Determination
Notional Gearing Assumption	ET: Notional gearing of 55% for the ET networks. Gas: Notional gearing of 60% for the gas networks.	Same as FD.
Financeability Check	ET: We consider all ET licensees are financeable on a notional capital structure basis, taking account of cost and incentive allowances, cost recovery and allowed returns if the following adjustment applies: • Capitalisation rate adjustment - reducing capitalisation rates for bucket two from natural to 85% Gas: We consider all GD and GT licensees are financeable on a notional capital structure basis, taking account of cost and incentive allowances, cost recovery and allowed returns.	Same as FD.

Background

5.1 GEMA is required to have regard to the need to secure that network companies are able to finance the activities which are the subject of obligations imposed by or under a range of legislation.[44] The assessments we perform to discharge this duty are often referred to as assessments of 'financeability'.

[44] Ofgem's principal statutory objective is to protect the interests of existing and future gas and electricity consumers. Ofgem also has a range of secondary duties including its duty to have regard to the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed on them (See section 3A(2)(b) of the Electricity Act 1989 and section 4AA(2)(b) of the Gas Act 1986).

5.2 Our Business Plan Guidance required companies to submit a financeability assessment in their Business Plans, accompanied by Board assurance that either the plan is financeable on both the notional and actual capital structure bases or that the Board has considered all applicable mitigating measures to improve financeability. The Business Plan Guidance also required companies to provide an explanation of their target credit rating, supported with evidence of the financial metrics on both a notional and an actual basis. We use this information to inform both our assessment of company Business Plans and also to inform our own financeability assessment.

5.3 We assess the financeability of energy networks based on the assumption that an efficient licensee adopts a notional capital structure. This is to ensure that consumers are protected from risks associated with actual financing decisions that licensees and their shareholders have made. Consistent with previous price controls, we consider it appropriate that the risks and rewards arising from financing decisions reside with investors.

5.4 Debt financeability is assessed at the final stage of the determination process to ensure that, when all the individual components, including totex, allowed returns, notional gearing, depreciation and capitalisation, are considered together, an efficient operator adopting the notional capital structure can generate sufficient cashflows to meet its debt obligations. Equity investability is considered in Chapter 3.

As discussed in Chapters 2 and 3 above, we have updated the assumptions for equity and debt based on further work since the Draft Determinations and changes in macro-economic factors such as interest rates and inflation forecasts.

Capitalisation Rate Adjustment

5.5 Our Draft Determinations financeability assessment for ET indicated that, without intervention, baseline credit quality of an efficient ET licensee adopting the notional capital structure, in the round, may not be consistent with a Baa1/BBB+ rating. This was primarily due to the scale and complexity of the capital investment programme, which significantly impacts the simulated rating outcome.

5.6 To address this, we proposed adjusting the capitalisation rate for bucket two Totex (further detail on capitalisation rates is provided in chapter 12) from a

natural average of c.100% to 85%, with rationale provided in in the Draft Determinations.[45]

Moody's scorecard considerations

5.7 In the Draft Determinations, we proposed continuing to use the Moody's methodology scorecard to create implied ratings given it is the most transparent and therefore replicable methodology of the three rating agencies that we currently rely upon. We also stated that we proposed seeking to model and analyse key credit ratios utilised by S&P and Fitch.

5.8 In RIIO-3, the key constraint for ET, in the Moody's scorecard, is the complexity of the capital programme. In the Draft Determinations we proposed a floor of B (the 2nd lowest) for this input which we considered to be reflective of a conservative yet pragmatic adjustment to account for the potential impact of the capital programme's scale on the company's credit profile. This approach took into account the strong and comprehensive regulatory mitigations.[46]

5.9 We consider that the proposed regulatory package significantly reduces the risks associated with delivering such a large investment programme, and that debt investors may, in aggregate, view the programme as less of a credit concern than our floor suggests. Nonetheless, it is recognised that a degree of uncertainty remains. Given the scale, value, and strategic importance of the RIIO-3 investment for consumers, we considered a cautious approach to be justified.

Target Credit Rating

5.10 In the Draft Determinations, we considered that the baseline credit quality of an efficient gas licensee adopting the notional capital structure is, in the round, generally stronger than Baa1/BBB+, which was the target rating most proposed by gas networks.

5.11 With respect to ET, based on the capitalisation rate adjustments discussed in the following section and complexity of the capital programme considerations, we considered that the baseline credit quality of an efficient ET licensee adopting the notional capital structure is, in the round, generally consistent with Baa1/BBB+, which was the target rating proposed by all ET networks.

5.12 In the Draft Determinations, we concluded that there is a strong consumer interest and evidence base in RIIO-3 to target credit quality to be consistent, in-

[45] RIIO-3 Draft Determinations – Finance Annex, paragraphs 5.39 & 5.40
[46] RIIO-3 Draft Determinations – Finance Annex, paragraph 5.33

the-round, with at least a Baa1/BBB+ rating. Our rationale reflected the following points:

- Scale of investment and financing needs: the RIIO-3 period will require significant investment and corresponding new debt capital for ET. Evidence submitted by companies indicates that a Baa1 rating enhances access to market capacity, at lower cost, supporting the efficient management of these financing requirements, compared to lower credit ratings
- Capitalisation rate adjustment: adjustments to the capitalisation rate aimed at achieving an overall Baa1/BBB+ rating constitute a NPV neutral cost for consumers over time
- Financial resilience: a Baa1/BBB+ credit rating provides good financial headroom to absorb adverse shocks. A stronger credit profile also supports long-term stability and confidence in the sector, which is particularly important given the scale and strategic importance of the RIIO-3 investment programme

Final Determinations decision

5.13 We consider the general approach to the financeability assessment that we applied at Draft Determinations remains appropriate. We focus on the notional company for assessing price control parameters and review notional company financeability analysis for individual notional licensees with reference to modelled credit metrics and ratings under different scenarios.

5.14 We continue to adopt an in-the-round approach to financeability testing, rather than rigid thresholds for individual credit metrics, as strict application can make ratings overly sensitive to minor variations. Credit rating agencies use different methodologies and apply judgement, and market participants often disagree on credit quality, which inherently involves subjectivity. Given these differences in interpretation, our in-the-round approach across different methodologies provides a balanced view, consistent with RIIO-2, as we do not consider it appropriate to rely solely on one agency's interpretation of the target rating.

5.15 For RIIO-3, uncertainty is heightened by sector trends and regulatory changes, including potential revisions to rating agency guidance. Our assessment and recommended actions take a conservative view of how external stakeholders may interpret these developments. To support this, we considered any changes to methodologies or thresholds driven by policy developments or structural shifts in the sector, noting that these updates may change following the publication of the Final Determinations.

5.16 Our financeability analysis enables us to test whether our proposed Final Determinations package allows the notional efficient operator to maintain sufficient headroom to service its debt.

5.17 In our analysis we consider:

- financial projections from our financial model(s)
- the implied Moody's methodology rating (as this is the most transparent and therefore replicable methodology of the three rating agencies that we currently rely upon)
- the strength of quantitative metrics for credit quality, particularly those emphasised by credit rating agencies or that are under pressure
- the strength of other metrics and qualitative factors
- stress testing results

5.18 We have used the following starting assumptions in our baseline case and higher case scenario modelling:

- The allowed return (WACC allowance) as set out in Chapter 4
- In the base case, totex allowances are assumed to be exactly matched by forecast totex expenditure, so there is no Totex Incentive Mechanism adjustment applied (including for uncertainty mechanisms(UMs))
- We have used higher totex scenarios for ET (10%) and gas (10%)
- Net debt is reset to the notional gearing assumption at the start of RIIO-3, with any opening de-gearing driven by a change in the notional gearing assumption assumed to be achieved by an equity injection (with an equity issuance allowance paid and used)
- Debt costs are assumed to equal the allowances set out in Chapter 2
- Index Linked Debt assumptions are set to the proposed assumption in Chapter 2
- Tax allowances are equal to tax costs, as calculated using the business plan financial model (BPFM)
- Opening RAV values to be based on totex forecasts for RIIO-2 as provided in licensees' Business Plan Data Template submissions, and inclusive of any known logged-up adjustments

- Lagged revenue impacts arising from RIIO-2 are excluded (eg inflation true up, cost pass-through adjustments, output incentive revenue and over / under collection of revenue)
- Depreciation rates are based on our decisions set out in Chapter 8
- Capitalisation rates are based on our decisions set out in Chapter 12 including the proposed ET adjustment of the bucket two cap rate to 85%
- Notional dividend yield assumed at 3% of regulatory equity
- Equity issuance transaction costs of 5% of any amount forecast to be issued

5.19 In our modelling, we maintain our approach to include equity injections and additional dividends to maintain the notional gearing level. However, we no longer apply a specific threshold above or below notional gearing to trigger these actions. Under the notional capital structure, efficient ET companies are expected to issue equity regularly throughout the RIIO-3 period. We also have continued to model equity injections to align gearing at the end of each regulatory year reflecting typical market practice.

5.20 In line with Chapter 10, we have modelled the effect of revenue profiling on notional company financeability. The impact on ratios is moderate, particularly when viewed as an average over the five-year price control period. We believe that the rating agencies are likely to focus on performance across the full price control period rather than individual years. On that basis, our revenue profiling financeability base case remains consistent with a Baa1/BBB+ rating.

5.21 Our modelling assumptions remain consistent with the behaviour of an efficient operator, ensuring that rapid growth in gearing does not create financeability challenges. We do not consider the assumed equity injections in our modelling are an issue for our conclusions on financeability. Our allowed return on equity is consistent with the opportunity cost of these equity injection requirements (including associated transaction costs), and so they are NPV neutral in their impact. As a result, we also do not consider it problematic for the conclusions of our debt financeability assessment that during a period of high RAV growth in the ET sector, equity holders, on a notional efficient basis, are modelled to be subject to negative cash flows (ie a negative net dividend yield after the modelled equity injections) for the duration of the price control to manage the level of gearing during a period of RAV growth.

5.22 We maintain our proposed floor of B in the scoring for complexity of the capital programme factor in our notional scorecard for ET, as described in paragraphs 5.7, 5.8 and 5.9.

5.23 Based on our modelling of the Final Determinations package, we continue to apply a 45-year asset life assumption, supported by the Cambridge Economic Policy Associates (CEPA) analysis referenced in our rationale in paragraph 5.55.

5.24 The modelling supports retention of an 85% capitalisation rate for bucket two totex for ET to sustain financeability. We anticipate that the level of capital spend to RAV for all ET companies should decline from RIIO-ET4 onwards, due to the increased RAV. As a result, the capital programme is expected to have a reduced influence on the simulated scorecard outcomes in the future.

5.25 We have carried out scenario analysis for each licensee, on a notional basis, reflecting our Final Determination package and, in particular, the range of RoRE outcomes based on company performance. RoRE analysis allows us to stress test notional businesses by examining a reasonable range of returns to which networks may be exposed. See Chapter 9 for RoRE graphs.

5.26 Similarly to the Draft Determinations[47], the objective of our stress tests is to assess whether the proposed Final Determinations package provides an appropriate degree of robustness to downside scenarios. In performing our duties, we must have regard to the need to secure that network companies are able to finance the activities which are the subject of obligations imposed by or under the relevant legislation. Network companies are also required by their licences to take all appropriate steps within their power to ensure that at all times they maintain an investment grade credit rating.

5.27 Our financeability analysis based on the Final Determinations package and an in the round approach to financeability assessment, as set out above, finds each licensee included in this RIIO-3 price control package, on a notional basis broadly achieving a simulated rating outcome of Baa1/BBB+.

5.28 Tables 17 and 18 set out the resulting financial ratios of our Final Determinations for both the baseline case and higher case scenarios, and a simulated credit rating consistent with the methodology that we applied at Draft Determinations. We present a range of key financial ratios of the main rating agencies including (Adjusted Interest Coverage Ratio) AICR and FFO (Funds From Operations)/ Net Debt (Moody's), FFO/ Net Debt (S&P) and PMICR (Post-Maintenance Interest

[47] RIIO-3 Draft Determinations – Finance Annex, page 91

Cover Ratio) (Fitch). For both the baseline and higher case scenarios, we also show the total simulated equity issuance.

Table 17: Baseline case modelled notional credit ratings and metrics (RIIO-3 average)

Licensee	AICR	Moody's - FFO/ Net Debt	Scoringcard Rating	Nominal PMICR	S&P - FFO/ Net Debt	Equity Issuance (£m)
Cadent	1.82	14%	A3	1.95	14%	8
NGN	1.82	14%	A3	1.95	14%	2
SGN Scotland	1.81	14%	A3	1.95	14%	0
SGN Southern	1.80	14%	A3	1.93	14%	7
WWU	1.80	14%	A3	1.92	14%	2
National Gas	1.82	14%	A3	2.04	14%	8
NGET	1.81	15%	A3	2.75	15%	6,482
SHET	1.74	16%	Baa1	3.39	16%	10,125
SPTL	1.78	14%	Baa1	2.80	14%	2,078

Table 18: Higher totex case modelled notional credit ratings and metrics (RIIO-3 average)

Licensee	AICR	Moody's - FFO/ Net Debt	Credit Rating	Nominal PMICR	S&P - FFO/ Net Debt	Equity Issuance (£m)
Cadent	1.82	14%	A3	1.95	14%	15
NGN	1.82	14%	A3	1.95	14%	4
SGN Scotland	1.80	14%	A3	1.95	14%	1
SGN Southern	1.80	14%	A3	1.92	14%	10
WWU	1.79	14%	A3	1.92	14%	4
National Gas	1.81	14%	A3	2.03	14%	18
NGET	1.81	15%	Baa1	2.78	15%	7,562
SHET	1.73	16%	Baa1	3.45	16%	11,296
SPTL	1.77	15%	Baa1	2.85	14%	2,377

Stakeholder responses and our rationale

Responses to FQ18: Do you agree with our approach to assessing financeability?

5.29 Companies were mostly supportive of the proposed Baa1/BBB+ target rating and believed that the Draft Determinations was mostly supportive of their

financeability across RIIO-3. Many noted that the proposed package lacked the durability required to ensure long-term financial resilience.

5.30 NGN and the ENA supported our proposal to target a minimum credit rating of Baa1/BBB. NGN believed we should incorporate the key methodologies used by credit rating agencies into our financeability assessment, alongside other relevant factors that influence credit opinions. While the ENA argued that we must not be selective in which ratios must be met.

5.31 While we place emphasis on Moody's scorecard, we also consider the key credit metrics and thresholds used by other major rating agencies when assessing financeability. We also recognise that strict application of thresholds for individual metrics can result in the modelled credit ratings being highly sensitive to very small variations. Accordingly, we continue to consider our financeability testing should take an in-the-round assessment, rather than applying strict threshold levels to particular credit metrics that must be met in all circumstances

5.32 Cadent disagreed with our proposed approach, stating that this places an overreliance on the metrics of a single credit rating agency, which is inconsistent with the newly introduced financial resilience measure requiring at least two investment-grade ratings. It said that our proposed approach relies on an outdated view of the sector that does not reflect the tightening of credit metrics proposed by rating agencies. Cadent claimed that our proposed approach fails to adequately consider the long-term financeability impacts of policies such as accelerated depreciation, which Cadent believes warrant deeper and more robust analysis.

5.33 NGN, National Gas, SGN and WWU also highlighted the importance of reflecting the tightening of credit metrics, which is reflective of a shift in how the gas sector is perceived, particularly the increased business profile risk associated with the energy transition for gas. National Gas highlighted the rating agency reactions to policies adopted in the Draft Determinations, which could render the Adjusted Interest Coverage Ratio (AICR) no longer fit for purpose. They also noted the impact of accelerated depreciation on Fitch's nominal post-maintenance interest coverage ratio (PMICR), with Fitch potentially introducing a new metric (Funds From Operations (FFO) interest coverage) to assess the debt-servicing capacity of GDNs under RIIO-3.

5.34 As mentioned in paragraph 5.31, while we acknowledge that we place emphasis on the Moody's scorecard, we also model credit metrics from S&P and Fitch. We will continue to monitor the perspectives of all major rating agencies which will

contribute to our comprehensive view of the notional company's credit profile. As outlined in the Draft Determinations, Moody's methodology remains the most transparent, making it easier to replicate. We have updated our credit metric thresholds to reflect the latest views from the rating agencies, noting that final confirmation of these thresholds will follow the publication of the Final Determinations. We do not consider that the tightening of these thresholds put our target Baa1/ BBB+ rating at risk. Going forward, we will also remain attentive to any changes in the methodology to ensure our approach stays current and aligned.

5.35 One network company believes that the index link debt assumption should reflect actual ET holdings and that this would ensure that they are suitably covered for fixed debt costs providing additional financeability support. It also argued that the justification for the B floor, in relation to the scoring for complexity of the capital programmed was insufficient, citing an Oxera report. Oxera argues that we overstates the effectiveness of our mitigation measures and that they do not go far enough to justify the floor imposed. It believes there remains a possibility that the actual scorecard outcome could be lower, which may result in the notional company being downgraded below the target credit rating of Baa1/ BBB+.

5.36 The index link debt assumption is addressed in paragraph 2.70. From a purely mechanistic perspective, reducing the complexity of the capital programme's score below B for a standalone notional company would result in a credit rating falling below the targeted Baa1/BBB+. The scoring for this factor is, however, more qualitative and extends beyond looking at the Capex to RAV ratio, which may not be directly correlated to the risk in all scenarios. In practice, Moody's has rarely assigned a score below B. Final rating outcomes reflect a more holistic assessment beyond the scorecard final output, incorporating factors such as the overall price control on average, execution risk, and scoring across the scorecard along with rating committee judgement. We therefore consider it unlikely that a company would be downgraded solely on the basis of one scoring factor. We maintain an ongoing dialogue with rating agencies and continue to consider our approach appropriate.

5.37 One network company proposed assessing financeability in a stress scenario where equity injections are delayed ensuring headroom in credit metrics. It also highlighted that our BPFM Moody's scorecard places greater weight on the final years of the price control, significantly influencing the overall score of the price control. Lastly, it suggested that there is a strong rationale for revenue profiling and that this approach could allocate revenues from the earlier years in RIIO-3,

when financeability metrics are stronger, to later years, where downward pressure on credit metrics is expected to increase. It also contends that this would also benefit consumers by allowing a more gradual increase in bills and is likely to be acceptable by investors who prefer a gradual earnings growth trajectory rather than fluctuations year on year.

5.38 We consider that delaying equity injections would only materially affect financeability if the injections were postponed beyond the five-year regulatory period. Within the period, timing adjustments may impact the year-on-year metrics, but from a financeability assessment perspective, if the equity is committed and received within the control period, the overall headroom in credit metrics should remain intact. The intent behind placing greater weight on the final years, while acknowledging that this does not perfectly mirror credit rating agency methodologies, is to support the development of a regulatory package that is self-contained within the price control period. It aims to reflect the expected rating outcome at the end of the specific five-year price control period. We have considered revenue profiling, which we set out in further detail in Chapter 10.

5.39 National Gas indicated broad agreement with our financeability approach, noting its general alignment with the position adopted in RIIO-2. However, it cautioned that while adjustments to capitalisation rates or asset lives may be appropriate in some cases, material changes of this nature risk undermining key regulatory principles, particularly intergenerational fairness and the long-term financeability of networks.

5.40 We aim to strike a balance within our financial framework, to ensure that costs are recovered over appropriate timeframes. The policies adopted in RIIO-3 are grounded in current evidence and outlooks, reflecting a balanced regulatory stance that seeks to protect both current and future consumers while maintaining investor confidence. Measures that stabilise financial performance in the near term, such as adjustments to capitalisation rates and asset lives, can support long-term financeability by enabling companies to continue delivering essential infrastructure upgrades and environmental improvements. These adjustments do not represent a departure from regulatory principles but rather are a pragmatic response to evolving financial realities.

5.41 WWU does not agree with our proposed approach and states that the matter is relevant to the ongoing Judicial Review proceedings, referring to its ongoing challenge to a CMA determination relating to RIIO-2 appeals. It argues that, within the flawed context of the financeability assessment of a notional company,

and without prejudice to its legal position, we should approach debt financeability assessment both for RIIO-GD3 and over the long run to 2050, with the following adjustments, combined with its scenarios:

- a dividend yield assumption set at or close to the cost of equity rate, before any account is taken of return of equity from accelerated RAV depreciation revenues
- assume a return of equity of 40% of RAV depreciation accelerated revenues in the year in which they are received
- remove the deadband between 60% and 55% gearing for triggering a special dividend
- ensure correct capitalisation rates are applied

5.42 We have addressed the first and third points in WWU's response in paragraph 3.99. Regarding the assumption on return of equity, we have not been provided with the broader context to assess the rationale behind the proposed adjustment and are therefore unable to comment on its appropriateness. On capitalisation rates, our modelling is intended to broadly reflect the natural capitalisation rates.

5.43 NPg recognises the Draft Determinations as a significant step toward addressing its long-standing concerns around long-term financeability. However, it expresses a mixed view on our approach to assessing debt financeability. NPg supports the need to assess debt financeability across at least three price control periods and welcomes the use of financial ratios evaluated by multiple rating agencies, particularly considering the new licence requirement of two investment grade credit ratings. It also highlights perceived shortcomings in the proposed approach, suggesting the inclusion of headroom into credit metrics, applying a 11% threshold for Moody's FFO/Net debt ratio to ensure an efficient company maintains two investment grade ratings, reflecting the highest expected investment level in the assessment and incorporating S&P's net debt to EBITDA ratio with a maximum threshold of 6x.

5.44 As noted in paragraphs 5.31 and 5.34, we currently consider, and will continue to model, credit metrics from a range of rating agencies. Regarding specific headroom in credit metrics, this is more appropriately considered at the level of individual companies, as it depends on specific factors such as their financing strategy, capital structure, and debt maturity profile. These elements can vary widely, making it difficult to define a one-size-fits-all level of headroom for a notional company. Building in additional headroom would go beyond our financeability objectives and would risk over-compensating the notional company,

ultimately at the expense of consumers. A financeability assessment that reflects the highest investment case is conceptually similar to embedding additional headroom in credit metrics. While this may be a prudent approach for actual companies, applying the same principle to a notional company risks over-compensating. This effectively builds in extra allowances for risks that the notional company, by design, does not face. Finally, while we do not disagree with the use of certain thresholds for Moody's FFO/Net Debt or the inclusion of S&P's Net Debt/EBITDA metric, it is important to recognise that these are just components of a broader credit assessment. As discussed elsewhere in the financeability section, final credit rating outcomes depend not only on scorecard metrics but, among other things, on the relative weighting of those metrics, the analyst's judgement, and ultimately, the decision of the credit rating committee.

5.45 SGN considers that the Draft Determinations lack a robust risk assessment and fail to define credible downside scenarios necessary to test financeability and investor return variability. It contends that our analysis relies heavily on assumptions rather than data-driven risk evaluation, overlooking key financial and cost recovery considerations. Consequently, SGN believes that it does not adequately assess potential asymmetries or deliver the impact analysis outlined in the SSMD. Independent analysis by SGN (via KPMG) highlights that, without the requested mitigations, the framework risks undermining safety obligations and credit ratings, with the notional company facing a negative RoRE and insufficient resilience to maintain investment-grade status in downside scenarios. SGN concludes that the Draft Determinations lack transparency on financeability and investability and suggests we must be assuming full RAV recovery to support its conclusions, an assumption that should be explicitly stated in Final Determinations, alongside evidence that we are working with the government to provide surety in this assumption.

5.46 We acknowledge SGN's concerns regarding the robustness of the risk assessment and the credibility of downside scenarios in the Draft Determinations. While the Draft Determinations incorporate a range of assumptions to reflect uncertainty, our approach is designed to be proportionate and consistent with the regulatory framework. It would require an exceptional level of underperformance to result in a four-notch downgrade out of investment grade status, which we consider highly unlikely under current conditions. Our approach to manage the risk of asset stranding is grounded in the current facts and outlook available to us today, avoiding the adoption of a more aggressive policy that may later prove unnecessary or misaligned with government direction. We consider that it reflects

a balanced regulatory stance, one that aims to protect existing and future consumers while maintaining investor confidence. We refer to Chapter 8 in the RIIO-3 Overview Document for a more detailed outline of our approach to gas depreciation.

5.47 One consumer group noted that several network companies benefited from inflation-driven RAV additions during RIIO-2, significantly improving their financeability. It argued that we have not set clear expectations for how this windfall should be distributed and called for us to demonstrate its impact on financeability and clarify any changes to distribution policies that may affect the assessment.

5.48 We acknowledge the consumer group's observation regarding the impact of inflation-driven RAV additions during RIIO-2 and their effect on network companies' financeability. The focus of this chapter is on the RIIO-3 framework and ensuring financeability across the upcoming price control period. Our assessment of financeability begins with companies' financial positions at the end of RIIO-2, which naturally reflects the effects of inflation on their financial metrics. From that point, we look forward and evaluate how companies are expected to perform under RIIO-3 conditions. We have introduced a nominal cost of debt allowance for the fixed-interest portion of debt in RIIO-3 to mitigate potential inflation-related shocks in the future. We do not set explicit rules for how companies should distribute financial gains, unless those gains arise from non-compliant or inefficient behaviour.

Responses to FQ19: Do you agree with our proposal to adjust bucket 2 capitalisation rates from natural rates to 85% for all ET licensees to support financeability? Are there alternative measures that stakeholders consider more appropriate?

5.49 Two ET companies and an ED network supported our proposal to adjust capitalisation rates at the suggested levels, but also noted that they viewed the approach as a short-term solution to addressing cashflow and financeability challenges in RIIO-3.

5.50 NPg noted that a lower capitalisation rate for this bucket could be considered to further support financeability. SHET responded that it required an uncertainty mechanism capitalisation rate of not greater than 82.5% and that the cumulative capitalisation rates across bucket one and two should be no more than 80%. It stated that a reduction would contribute to a reduction in equity requirements albeit the level of new equity would still be unprecedented. It argued that the

company with the greatest investment requirement should have the most cashflow support and therefore the lowest capitalisation rate.

5.51 Following the updated price control modelling for the Final Determinations, we observe a convergence in aggregate capitalisation rates across the ET companies, alongside an overall reduction. Based on our Final Determination analysis, a capitalisation rate of 85% remains the appropriate level to support financeability. We continue to consider that maintaining a consistent approach to capitalisation rates across the ET sector represents the most effective regulatory strategy. Applying a consistent approach avoids the complexity of tailoring rates for individual companies, which would conflict with the notional company principle. Consistent capitalisation rates also reduce the risk of perceived bias or preferential treatment and eliminate subjectivity, particularly given the differences in timing, totex mix, and re-opener volumes across networks. Moreover, given the broader financial structure and resource flexibility within the wider corporate group of some network companies, the requirement for an equity injection at the notional company level does not necessarily imply that a corresponding equity raise would occur in practice. Lastly, when considering a target capitalisation rate across buckets one and two, there remains uncertainty around the eventual level of re-opener totex during RIIO-3. As a result, targeting a specific overall rate at Final Determinations would ignore this inherent variability.

5.52 SPT raised concerns about the predictability of future adjustments to capitalisation rates and said that we should explore a more sustainable and predictable approach to enhance ET's financeability alongside reasonable capitalisations rates, such as considering asset lives adjustment and depreciation policy. NGET indicated that long-term analysis suggests the proposed capitalisation intervention will require reassessment before RIIO-4 to ensure it remains a sustainable solution. It specifically highlighted depreciation policy and the RAV differential as potential long-term financeability mechanisms to support sustained cashflows.

5.53 We recognise the importance of predictability in capitalisation rates and share the objective of providing a stable framework for stakeholders. Alongside this, we aim to balance transparency and consistency with flexibility to respond to market dynamics and evolving conditions, ensuring our approach supports both efficient financing and long-term sustainability. While we do consider asset lives and depreciation, these measures generally have limited short-term impact and may introduce longer-term risks. Our approach seeks to balance these factors

carefully, ensuring they are managed in a way that preserves stability and supports long-term sustainability.

5.54 One network company further stated that asset lives on new assets should be reduced to 35 years as this reflected the technical lifespan of the assets and accounts for the increasing proportion of offshore projects. It added that it helps to mitigate significant cashflow challenges, both in the short and long term. It noted that the retention of 45-year asset lives places downgrade pressure on key credit metrics in the latter half of the period, with further deterioration in RIIO-4.

5.55 We maintain that an in the round approach to asset lives remains the most appropriate approach. Our decision to retain the existing 45-year asset life assumption is supported by analysis from CEPA,[48] which found that the current weighted average technical life of assets to be 55 years. To date, we have still not received substantive evidence to justify a significant change. We have reviewed the key credit metrics across the RIIO-3 period and remain confident that using a 45-year asset life falls within the bounds of our target credit rating for the notional company.

5.56 One supplier responded that the proposed reduction in capitalisation rates to 85% should be reconsidered while also suggesting that a transition period should be applied. It expressed concern that our approach could create financeability risks down the value chain, particularly if charges increased immediately from April 2026.

5.57 We consider that the financeability assessment should be based on the overall price control package and capitalisation rate policy decisions should not be altered to address financeability risks further down the value chain. However, recognising the step change in allowed revenues from RIIO-2 to RIIO-3 and its potential impact on the non-domestic supply market, we have set out our targeted revenue profiling decisions in Chapter 10.

Long-term financeability considerations

5.58 In Draft Determinations, we undertook long-term modelling of the FFO/Net Debt, PMICR and AICR ratios, using a simplified approach based on an extended version of the PCFM. This modelling broadly extrapolates RIIO-3 price control policies and the current macroeconomic environment into future periods.

[48] RIIO-ET3: Economic Lives of Electricity Transmission Network Assets

5.59 In our ET modelling, we assumed the capitalisation rate applied in RIIO-4 aligns to RIIO-3 (85% for bucket two), while in RIIO-5 we assumed these revert to RIIO-2 regulatory rates. Totex is assumed be the same in RIIO-4 as RIIO-3. In RIIO-5, totex is assumed to drop to RIIO-2 levels (in real terms).

5.60 In our gas modelling we assumed the capitalisation rate applied in RIIO-4 and RIIO-5 aligns to RIIO-3; totex is also assumed to be equal to RIIO-3 levels

5.61 Our modelling in the Draft Determinations showed on average, that companies, on a notional efficient basis, would broadly align to minimum credit rating expectations at the Baa1/ BBB+ credit rating.

Final Determinations decision

5.62 As we did in the Draft Determinations, for the Final Determinations we have undertaken long-term modelling of PMICR and AICR ratios, using a simplified approach based on an extended version of the PCFM. This modelling broadly extrapolates RIIO-3 price control policies and the current macroeconomic environment into future periods. We also applied the same assumptions described in paragraphs 5.59 and 5.60.

5.63 It is important to emphasise that the assumptions underpinning this analysis are necessarily simplified and may not reflect the actual policies or allowances that will be adopted in future price controls.

5.64 The limitations inherent in long-term modelling cited above mean that apparent weakness in the projected ratios should not necessarily be viewed as definitive evidence to prompt immediate action. Future policy developments or adjustments to allowances could materially alter the financial outlook, potentially mitigating any issues currently forecast. Moreover, modest financeability issues identified may be more appropriately addressed at the time of the relevant price control, when more accurate and up-to-date information will be available. Despite these limitations, the modelling remains a useful tool for identifying potential material long-term structural trends that may be best addressed within the RIIO-3 framework, rather than deferred to subsequent periods

Table 19: Long-term modelling for RIIO-3 – Moody's AICR ratio (sector and RIIO average - notional)

	RIIO-3	RIIO-4	RIIO-5	Threshold
GD	1.81	2.13	2.19	1.6
GT	1.82	1.78	1.78	1.6
ET	1.77	1.74	1.72	1.4

Table 20: Long-term modelling for RIIO-3 – Fitch PMICR ratio (sector and RIIO average - notional)

	RIIO-3	RIIO-4	RIIO-5	Threshold
GD	1.94	2.26	2.31	2.0
GT	2.04	2.02	2.02	2.0
ET	3.06	2.52	2.06	2.0

Table 21: Long-term modelling for RIIO-3 – S&P FFO/ Net Debt ratio (sector and RIIO average - notional)

	RIIO-3	RIIO-4	RIIO-5	Threshold
GD	13.80%	19.60%	26.70%	~13%
GT	14.00%	14.20%	14.00%	~13%
ET	15.10%	12.30%	10.40%	~9%

Table 22: Long-term modelling for RIIO-3 – Moody's FFO/ Net Debt ratio (sector and RIIO average - notional)

	RIIO-3	RIIO-4	RIIO-5	Threshold
GD	14.30%	20.10%	27.20%	11%
GT	14.40%	14.70%	14.40%	11%
ET	15.10%	12.30%	10.40%	11%

Stakeholder responses and our rationale

Responses to FQ20: Do stakeholders have views or evidence on long-term financeability considerations, including the appropriateness of the proposed asset lives?

5.65 Companies emphasised that while short-term measures such as higher capitalisation rates help address immediate cashflow and financeability challenges, they expressed concerns about sustainability, comprehensiveness, and predictability. They argued that reliance on temporary levers creates uncertainty for investors, particularly as key credit metrics are forecasted to deteriorate beyond RIIO-T3. One network company highlighted that adjusting capitalisation rates masks underlying issues such as persistently high real financing costs and an outdated depreciation policy. They noted that when the capitalisation rate lever is removed in RIIO-5, modelling shows a sharp deterioration in credit metrics, which they contend exposes the fragility of the current framework.

5.66 To ensure long-term resilience, companies advocated for a more predictable and forward-looking approach that goes beyond capitalisation adjustments. They recommended reviewing asset lives, particularly for new assets, with one network company reiterating its proposal for a 35-year asset life, and exploring alternative depreciation methods to better reflect the economic life of assets and evolving

investment needs. They view these structural changes, combined with clear signalling of future policy direction, as essential to provide stability, maintain creditworthiness, and deliver a regulatory framework that supports sustainable financeability across future price control periods.

5.67 We recognise the concerns raised around sustainability, comprehensiveness, and predictability, and agree these are important considerations for the long-term resilience of our regulatory framework. Our approach aims to balance predictability with flexibility, enabling us to respond to evolving market conditions while maintaining transparency and stability for stakeholders. While capitalisation adjustments have been used to address short-term financeability challenges, they are not necessarily effective for longer term structural changes and should be applied judiciously. Our view is that capitalisation should remain part of the toolkit, but that it is complemented by a clear and predictable long-term strategy to ensure sustainable financeability and investor confidence. It is important to note that forecasting financial outcomes 10 or 15 years ahead is inherently challenging and highly assumption driven. Market conditions, policy developments, and technology changes can significantly alter the outlook, which is why we take a cautious, simplistic and evidence-based approach to long-term modelling. We are committed to engaging with stakeholders on options for RIIO-4 and beyond, including continued dialogue with all stakeholders around depreciation methods and asset lives, to ensure the framework remains robust and sustainable. Clear signalling of future policy direction remains a priority.

5.68 A key concern for the gas companies was that the modelling does not fully account for the future affordability of customer bills, a risk that accelerated depreciation alone cannot resolve. Cadent highlighted that the combined impact of totex profiles, accelerated depreciation, and accelerating customer loss could lead to materially higher bills in later periods, raising doubts about economic feasibility and, in turn, financeability and investability. It argued that, while accelerated depreciation in RIIO-GD3 aims to mitigate asset stranding, our own scenarios show bills reaching unsustainable levels. SGN again noted that there appears to be an implicit assumption that future affordability issues with bills can be resolved and the notional company can recover all revenue. National Gas mentioned that the consultation on asset transfer values had left various issues unresolved, such as the life applied when valuing assets for transfers and the treatment of decommissioning/disconnection costs. Companies therefore call for a more thorough long-term financeability assessment that incorporates affordability risks, scenario analysis and clarity on unresolved issues such as asset valuation

for transfers and treatment of decommissioning costs and RAV recoverability. In addition, they want us to engage with companies on our analysis and assumptions, to ensure that the conclusions from the analysis are robust.

5.69 We recognise the need to balance long-term affordability for customers with financeability and investor confidence. As a regulator, safeguarding consumer interests is central to our role, which includes maintaining affordability while enabling a fair return for investors. Consistent with paragraph 5.46, our approach is based on the current facts and outlook, avoiding overly aggressive policies that could later prove unnecessary or conflict with government direction. Accelerated depreciation under RIIO-3 helps mitigate asset stranding risk, but affordability remains a key priority. We will continue to engage with companies and government to review assumptions and inform future policy decisions.

6. Financial resilience

Purpose: Encourage companies to adopt a prudent and responsible approach to financial arrangements, provide us early warning of financial distress, and ability to consider mitigations and/or restrict activities in the event of financial deterioration.

Benefits: Measures benefit consumers by making company failure less likely and/or increasing the chance and quantum of recovery in the event of failure. Investors benefit from lower risks assumed by companies and increasing chance of investment recovery.

Final Determinations summary

Parameter	Final Determination	Draft Determination
Measure 1 - more than one credit rating	Replace the current obligation for licensees to "use reasonable endeavours" with a requirement that they "must" maintain more than one investment grade rating	Same as FD.
Measure 2 - distribution lock-up trigger at 75% Gearing	Include an additional distribution lock-up trigger when the licensee reaches 75% Regulatory Gearing (calculated as Net Debt / RAV) along with the existing trigger when the licensee reaches a credit rating of BBB- with a Negative Watch/Outlook	Same as FD.
Measure 3 - extended certificates in relation to financial resources	Require licensees to state that they have sufficient financial resources and financial facilities to cover the entire price control period or a minimum of three years ahead. Additionally, the certificates in relation to financial resources would have to include references to stress testing analysis undertaken prior to the licensee issuing the certificate	Same as FD.

Background

6.1 Financial resilience refers to the ability of companies to maintain sufficient safeguards or headroom to prevent or manage the risk of financial distress in the event of adverse shocks. Our principal objective is to protect the interests of consumers and our requirements relating to financial resilience aim to shield consumers from the negative effects of financial vulnerability or failure. We constantly strive to do this by monitoring, enhancing provisions, and promoting a prudent and responsible approach to financial resilience by network companies.

6.2 Within the parameters set by the price control, licence and company law, network companies and their shareholders retain considerable discretion over decisions related to financing and capital structure. We expect companies to manage their own financial risks and for shareholders, rather than consumers, to bear the direct consequences, whether gains or losses, of those decisions.

6.3 Our extensive analysis in the SSMD[49], supported by our Draft Determinations, showed that financial resilience measures are more effective in protecting consumers when adopted in advance rather than as a reaction to financial distress. The tools available to us are designed to provide early indications of financial vulnerability, enabling both us and licensees to explore potential mitigations and solutions. The goal is to reduce the likelihood of failure and/or enhance the prospects and extent of recovery for the benefit of consumers.

6.4 In our Draft Determinations[50] we proposed to reinforce the existing financial resilience provisions and adopt the suite of measures proposed at the SSMD:

- Amend the Credit Rating of the licensee and related obligations[51] to replace the current obligation for licensees to "use reasonable endeavours" with a requirement that they "must" maintain more than one investment grade rating (Measure 1)
- Amend the Indebtedness conditions[52] to include an additional distribution lock-up trigger when the licensee reaches 75% Regulatory Gearing (calculated as Net Debt / RAV) along with the existing trigger when the licensee reaches a credit rating of BBB- with a Negative Watch/Outlook (Measure 2)
- Amend the Availability of Resources (AOR) obligations[53] to require licensees to state that they have sufficient financial resources and financial facilities to cover the entire price control period or a minimum of three years ahead (Measure 3). Additionally, the certificates in relation to financial resources would have to include references to stress testing analysis undertaken prior to the licensee issuing the certificate

[49] RIIO-3 Sector Specific Methodology Decision - Finance Annex, paragraphs 6.19-27
[50] RIIO-3 Draft Determinations - Finance Annex, paragraph 6.1
[51] Electricity Transmission Standard Licence Conditions Condition B10 and Gas Standard Special Condition - PART A Consolidated Condition A38
[52] Electricity Transmission Standard Licence Conditions Condition B9 and Gas Standard Special Condition - PART A Consolidated Condition A39
[53] Electricity Transmission Standard Licence Conditions Condition B7 and Gas Standard Special Condition - PART A Consolidated Condition A37

Measure 1 - more than one credit rating

Final Determinations decision

6.5 Our Final Determinations decision is to implement Measure 1 as set out in the SSMD and Draft Determinations. This means we will modify the current obligation for licensees to "use reasonable endeavours" to maintain one investment grade credit rating to "require" licensees to maintain more than one investment grade rating at all times.

6.6 For the avoidance of doubt, this measure refers to an Issuer Credit Rating (ICR), a rating issued for the entity as a whole and as defined by the current licence conditions[54], rather than a rating for a specific debt instrument. This is widely known as a Long Term Issuer Rating for Moody's, Issuer Credit Rating for S&P, Issuer Rating for DBRS, or an Issuer Default Rating (IDR) for Fitch.

Stakeholder responses and our rationale

Responses to FQ21: Do you agree with our proposal to implement the Financial Resilience measures as laid out in our SSMD and the proposed methodologies?

6.7 NGN and SHET said that compliance with this measure depends on the price control package financeability and investability which must sustain an investment grade level of credit ratings. We note that in setting parameters for the efficient notional company we have a duty to have regard to whether approved price control packages are financeable for the licensees to attract financing and to support long-term investments for the benefit of consumers.

6.8 SGN asked for us to use Fitch's senior unsecured debt rating definition when monitoring compliance with credit rating licence conditions, rather than the Issuer Default Rating, as that "appropriately captures the creditworthiness of an entity". Throughout the RIIO-3 process stages, we have observed similar views from the licensees. We consider the requirement for issuer ratings to be a central component of the Ofgem licence. This is to ensure that we capture the overall credit position of the company rather than elements of the debt structure such as loss recoverability.

6.9 We consider it important that the rating does not factor in loss recoverability as this does not reflect consumer risk exposure. We understand that Fitch is the only credit rating agency that generally applies a one-notch uplift from the IDR to

[54] Electricity Transmission Standard Licence Conditions Condition A1: Definitions and interpretation, and Gas Standard Special Condition - PART A Consolidated Condition A3: Definitions and interpretation

derive the senior unsecured debt rating for utilities, whereas other agencies align senior unsecured rating with the ICR. Therefore, we will continue to treat Fitch's IDR as equivalent to Moody's and S&P ICRs to align with our intent in the licence conditions and ensure consistency across credit rating agencies.

6.10 SGN said that by implementing this measure we are imposing an "absolute requirement on ratings that are not fully in control of licensees", referring to possible downgrades by credit rating agencies of the regulatory regime or similar actions on the gas sector overall due to policy decisions on depreciation profiles. While we understand that external factors can influence a company's rating, we note that financing decisions and operational performance remain primary drivers of a change in a company's rating and therefore the resulting credit profile reflects the overall financial resilience. Moreover, maintaining an investment-grade rating is also reflective of demonstrating robust governance, prudent financial management and credible mitigation strategies in the face of change.

Measure 2 - distribution lock-up trigger at 75% regulatory gearing

Final Determinations decision

6.11 Our Final Determinations decision is to implement Measure 2 as set out in the SSMD and Draft Determinations. This will see the introduction of a distributions lock-up trigger if the licensee has or, based on reasonable forecasts, will have a Regulatory Gearing ratio of 75% or higher.

6.12 As stated in the Draft Determinations, the 75% gearing trigger will have both a backward-looking and a forward-looking test. The backward-looking test means licensees will consider their actual regulatory gearing ratio as reported at the closing of the last reporting year, using nominal figures for Net Debt and RAV. The forward-looking test will be based on projected gearing for the end of the current reporting year, using reasonable assumptions and forecasts made by the licensee at the time of distribution.

6.13 For the avoidance of doubt, and as stated in the Draft Determinations, the intent of this measure is to achieve an impact that is identical to that of the existing distributions lock-up when the licensee's credit rating is falling to the lowest investment grade and is on negative watch / outlook. This means that the 75% gearing lock-up will encompass transactions as delineated in the current licence conditions[55].

[55] Electricity Transmission Standard Licence Conditions Condition B9, paragraph 1(b) items (i) to (vii) and Gas Standard Special Condition - PART A Consolidated Condition A39, paragraph 1(b) items (i) to (vii)

Stakeholder responses and our rationale

Responses to FQ21: Do you agree with our proposal to implement the Financial Resilience measures as laid out in our SSMD and the proposed methodologies?

6.14 NGN, SHET and SGN said there is no evidence to suggest the current measures are not working or suggest the need for gearing thresholds. We reiterate our SSMD position[56] that these measures, including the distributions lock-up trigger at 75% gearing, are intended to minimise future exposure to risks rather than change current behaviour. Our role is to ensure long-term resilience and therefore we are designing safeguards to achieve that and enhance consumer protection.

6.15 NGN highlighted that a declining RAV environment in the gas sector might lead to triggering the lock-up, sending "unnecessary negative signals and an impression of financial instability to investors". SGN also shared the view that our proposed measure can negatively impact investors' perception as it can be seen as regulatory intervention in company financing choices. We recognise that a decline in RAV, irrespective of the cause, will lead to reduced financial headroom. However, we expect companies to manage their capital structure responsibly and maintain prudent gearing. We also believe that having additional protections, such as the distributions lock-up, in place will actually support investor confidence in regulatory oversight and provide assurance of enhanced scrutiny of company financial discipline.

6.16 SHET and Cadent said that there is no value for additional safeguards on distributions and that imposing lock-ups would not benefit consumers. We disagree with this view and consider that distributions lock-ups can benefit consumers directly by ensuring that cash is retained within the regulatory ringfence during periods of elevated financial risk, supporting continued investment and preventing service disruption and increased costs that are ultimately borne by consumers.

6.17 SGN considered it too strict to measure a single ratio for the distribution lock-up. We note that Regulatory Gearing as measured by Net Debt/RAV is a widely accepted and transparent benchmark measure used to assess financial capacity in the sector. The ratio is broadly aligned to thresholds in rating methodologies such as Moody's, existing financial covenant levels set by debt markets and analogous

[56] RIIO-3 Sector Specific Methodology Decision - Finance Annex, paragraphs 6.19-22

sectors. Therefore, the 75% gearing threshold is an indicator within a broader assessment of business and financial risk.

Measure 3 - extended certificates in relation to financial resources

Final Determinations decision

6.18 Our Final Determinations decision is to implement Measure 3 as set out in the SSMD and Draft Determinations. This will require licensees to submit an additional annual certificate in relation to financial resources, which refers to the licensees' sufficiency of financial resources for the whole price control period or a minimum of three years ahead.

6.19 For the avoidance of doubt, this certificate will not require pre-funding or maintaining more liquidity than necessary to cover the timeframe required by the certificate. Instead, the certificate will require that the licensees use relevant assumptions in relation to the availability of financial markets for any financing or refinancing requirements or around equity injections. Where the certificate covers two different price control periods and the parameters of the new price control are not yet determined, licensees should note we have a duty to have regard to the need to ensure that business plans are financeable when setting future price controls.

6.20 The new extended certificate will need to be accompanied by a statement of factors, as proposed in Draft Determinations[57], which states the factors considered by licensees in issuing the certificate. It will also require company board approval and sign-off from a licensee director. However, it will not require an independent auditor opinion to be provided.

6.21 In addition, this measure will require licensees to include explicit references to stress tests undertaken prior to issuing the certificates. For the avoidance of doubt, this refers both to the existing 12-month certificate in relation to financial resources and the new extended version of the certificate.

Stakeholder responses and our rationale

Responses to FQ21: Do you agree with our proposal to implement the Financial Resilience measures as laid out in our SSMD and the proposed methodologies?

6.22 NGN and Cadent stated their disagreement with the measure and have said that we have not made the case to justify the need for implementing this measure. We note that we have outlined the rationale for introducing this measure across

[57] RIIO-3 Draft Determinations - Finance Annex, paragraph 6.10

our SSMD and Draft Determinations[58]. To reiterate, the nature of this measure is preventative, aiming to reduce risk exposures and provide visibility and early warning in the case of financial deterioration.

6.23 SHET and NGN said that expanding the financial resources certification would require funding the price control period in advance, leading to higher costs of carry. As stated in the SSMD and Draft Determinations, this proposed measure does not mandate pre-financing but rather a forward-looking assessment of resource sufficiency. This means that, for the purposes of elaborating the extended certificate, the company board can consider assumptions made in relation to the availability of financial markets for any financing or refinancing requirements or equity injection. Moreover, unlike the 12-month certificate, the extended certificate does not need to be accompanied by an auditor's opinion.

6.24 NGN said that this certificate can span across two price control periods, with no visibility of the future parameters. We recognise that licensees may not have certainty over policy decisions for future price control periods, however licensees should note we have a duty to have regard to the need to ensure that licensees' business plans are financeable when setting future price controls. We also expect any prudent licensee to plan for the long-term as part of their normal business planning process.

6.25 SGN said it is unclear on how this measure will be implemented. We note that this measure will be implemented via licence conditions, which will capture the implementation detail.

6.26 SHET stated that our measure duplicates the work undertaken for the annual 'going concern' statement. We note that our extended certification is different than the going concern statement, as our required certificate refers to an extended timeframe, is based on long-term assumptions about company access to funding and will not require an auditor's evaluation.

6.27 SGN argued that the assumptions used by the certificate should be agreed by its company board as such assumptions are company specific, while NGN called for guidance on the methodology expected to adopt for stress testing. We recognise that company boards are best placed to assess their own financial plans and assumptions, and we expect them to take ownership of this process. We will provide guidance on which factors to consider when undertaking stress tests in

[58] RIIO-3 Sector Specific Methodology Decision - Finance Annex, paragraphs 6.76-81, and RIIO-3 Draft Determinations - Finance Annex, paragraphs 6.25-26

the Regulatory Instructions and Guidance (RIGs), but ultimately, we expect companies to ensure assumptions are relevant and reasonable.

Other stakeholder responses

6.28 In response to our FQ21, National Gas and NGET agreed with our measures and stated that they achieve the right balance of enhancing financial resilience provisions without imposing undue restrictions on network companies. The other six licensees disagreed with our measures for the reasons set out below.

6.29 SPT and Cadent said that it is unnecessary to strengthen the existing measures as the licensees' financial resilience has been strong since the energy networks privatisation. However, even where financial resilience is strong, and there is an existing strong regulatory framework, it is important to ensure that this continues and the framework is aligned to the macroeconomic changes and sector challenges, such as the licensees' endeavours to support decarbonisation, which have and continue to evolve over time. We consider that strengthening current measures ensures proactive protection of consumers and maintains confidence in the sector's long-term stability.

6.30 SPT highlighted that it is inappropriate for us to apply financial resilience rules from sectors with recent financial issues such as UK Energy Retail or UK Water. SPT did not provide reasoning or evidence as to why this would be inappropriate. Similarly, Cadent and SGN stated that we did not provide evidence to support or justify stricter financial resilience measures, while NGN said our measures go beyond practices in other sectors. We disagree with the view that it is inappropriate. We consider that financial issues seen in those sectors prove that vulnerabilities such as excessive leverage or lack of appropriate dividend restrictions can lead to significant negative impacts on consumers if not managed properly. Our proposed measures are preventative by design and informed by cross-sectoral issues, lessons learnt and best practice to ensure early detection of financial stress and safeguard consumers from similar adverse outcomes.

6.31 SPT and WWU disagreed with the overall strengthening of financial resilience measures, suggesting that we did not consider the concerns they raised in their responses to RIIO-3 SSMC and Business Plan submissions, and asked for those concerns to be reviewed. We noted their views and have carefully considered all representations made by licensees at every consultation stage of the RIIO-3

process. We provided extensive rationale in the SSMD[59] and are building on this further in the sections below.

6.32 SPT asked us to provide clearer guidance on how these measures will be implemented in practice. We note that these measures will be implemented via licence conditions changes, which have been presented to all licensees in the working group as well as in the licence changes consultation in July 2025[60]. Guidance is provided in the sections below and will also be captured in the statutory consultation on licence conditions changes.

6.33 SGN called for us to tackle financial resilience measures in the Energy Networks Ringfence Review[61] rather than in the RIIO-3 process. We note that the measures we are implementing via this process have been identified as suitable and proposed for implementation prior to the Ringfence Review launch, which may complete after the RIIO-3 period for ET, GT and GD companies commences. It is in the consumer interest to implement these measures promptly and therefore take them forward through the current RIIO process. Additional measures proposed to further enhance consumer protection are being consulted on via the Energy Networks Ringfence Review[62].

6.34 We have reviewed all representations made by licensees regarding our Draft Determinations. While two licensees agreed with our measures, six of them disagreed and believed strengthening financial resilience is unnecessary or unjustified, although there was no evidence provided to support these views. We consider that the financial resilience measures proposed will benefit consumers and that there is no basis to deviate from our Draft Determinations position. Our Final Determinations decision is to implement the financial resilience measures as set out in the SSMD and Draft Determinations.

[59] RIIO-3 Draft Determinations - Finance Annex, paragraphs 6.17-27
[60] RIIO-3 initial licence consultation
[61] Ring fence review: energy networks call for input and Energy networks ring-fence review: call for input conclusion
[62] Energy Networks Ring-fence Review consultation | Ofgem

7. Corporation tax

Purpose: To provide an allowance to compensate for the efficient tax payments of the notional company

Benefits: Providing a notional allowance enables companies to recover amounts required to cover their tax costs while incentivising them to manage their tax affairs efficiently thereby keeping costs lower for consumers. The additional protections reduce the risk of consumers providing an allowance for tax costs which are not ultimately borne by the licensee.

Final Determinations summary

Parameter	Final Determination	Draft Determination
Approach to tax allowance	Notional Allowance with additional protections	Same as FD.
Tax forecasting penalty	A tax forecasting penalty is not required	Same as FD.
Update of Tax Clawback terms	ANDt and TDNIt definitions will be updated within the PCFH	Same as FD.
Inflation Accretion	Inflation accretion will be included within the definition of ANDt	Same as FD.
Tax clawback excess interest methodology	The methodology will be unchanged from RIIO-2	Same as FD.

Background

7.1 Our Draft Determinations decision was to retain the method of providing tax allowances used within the RIIO-2 price control period. This is a notional allowance with additional protections.

7.2 These protections are:

- Tax Trigger Event Mechanism
- Tax Clawback
- Tax Review

7.3 In the Draft Determinations we consulted on two questions:

- FQ22. Do you agree with the proposed position that by including robust protections within the Price Control Financial Handbook, a tax forecasting penalty is not required?

- FQ23. Do you agree that the definitions for ANDt and TDNIt should be updated to reflect the principles (outlined in paragraph 7.41 of the Draft Determinations)?

Notional Allowance with additional protections

7.4 At SSMD we proposed to retain the Notional Allowance with additional protections, which had also been highlighted in the SSMC. Our Final Determinations decision is to retain the Notional Allowance with additional protections. The tax clawback 'glide-path' which featured in RIIO-2 is no longer needed and will not be retained. It is no longer needed because gearing limits are maintained at the same level between RIIO-2 and RIIO-3. And, as explained in paragraph 7.12 of the SSMD Finance Annex, to include such a 'glide path' would inappropriately incentivise the conduct of licensees who remain outside applicable gearing limits under RIIO-2.

7.5 Our rationale remains consistent with the rationale that we provided at SSMD. In line with RIIO-2, the Notional Allowance remains the most appropriate basis of calculation for the tax allowance. We have not identified any clear evidence that a change to a pass-through approach would provide better value for the consumer and furthermore, we consider that it would introduce inconsistency in the calculation of the allowance, which may be to the advantage of some networks and the disadvantage of others. The existing approach to taxation is neutral to corporate structure.

7.6 Within its business plan submission SHET re-stated its position that it considers that we should move to a pass-through method for providing tax allowances to licensees. This was re-stated in Draft Determinations submissions. No new evidence was presented by SHET.

7.7 We therefore consider it reasonable to make the decision that was proposed at SSMD and in the Draft Determinations.

Tax forecasting penalty

Background

7.8 In the Draft Determinations we considered whether a tax forecasting penalty was required, set out our reasoning for proposing that it was not, and asked the consultation question set out above.

Final Determinations decision

7.9 We did not propose a tax forecasting penalty at Draft Determinations for RIIO-3. We instead decided to strengthen the guidance included within the Price Control

Financial Handbook to mitigate the risk of deliberate / negligent tax mis-forecasting which could impact consumers. Respondents universally agreed that such a penalty was not necessary for RIIO-3.

7.10 Respondents questioned the need for further protections in the PCFH. In particular WWU stated that it considers the proposed changes to the PCFH to expand the scope of the tax review protection from the RIIO-2 position. Our view is that the changes to the PCFH make explicit the position which has always been implicit in the licence condition. The tax review is intended to apply in circumstances where there is a material unexplained difference between the licensee's actual tax return and the PCFM allowance. However, it should also apply where the licensee has updated variable values in the PCFM in line with its actual tax return to optimise the tax position of its wider corporate group, where this would not have been done by the notional efficient company on a standalone basis.

Tax Clawback Definitions of ANDt and TDNIt

Background

7.11 In November 2024 we published a call for input in respect of a proposed review of the definitions of ANDt and TDNIt in the PCFH. The aim was to update the definitions to reflect the changes in accounting standards and tax legislation and practice since the original guidance in respect of the tax clawback was produced in 2009.[63] and amended in the 2019 Regulatory Instructions and Guidance. In the response document we stated that we would consult on this within the RIIO-3 Draft Determinations.

Final Determinations decision

7.12 We have decided to include revised definitions for the tax clawback values ANDt and TDNIt within the Price Control Financial Handbook for RIIO-3.

7.13 In the Draft Determinations we set out the principles for the revision of the definitions and consulted on the proposal. The revised definitions are included within the PCFH which was issued for consultation, and is expected to be issued for statutory consultation in December 2025.

7.14 Licensees generally supported the updates, however NGET stated that it considers that fair value (FV) movements should continue to be excluded. It stated that FV movements are generally timing differences which should net to nil

[63] Open letter - clawback of tax benefit due to excess gearing

across the life of the underlying instrument. It stated that the inclusion of FV movements could result in a tax clawback as a result of a FV movement which is not reversed in later periods. Whilst this is correct, it only considers one side of the equation. Excluding FV movements could similarly result in tax clawbacks in periods where there is no actual tax deduction arising within the company.

7.15 The gearing test should provide comfort that such movements can be mitigated by licensees. As we are only including FV movements in financing derivatives where the movements are taxable/deductible (i.e. where the licensee has not entered into, or where the instruments cannot be brought within, the Disregard Regulations for Derivative Contracts). In such cases, licensees are in effect choosing volatility within their tax charge. Therefore, if we do not make the change a licensee could suffer a tax clawback in a period where it is not receiving the effective tax relief.

7.16 We consider aligning the tax relief and tax clawback to be a better approach for RIIO-3. We acknowledge that the revised definitions of ANDt and TDNIt may result in changes to how the tax clawback mechanism operates for some licensees, particularly those with significant derivative exposures. However, we consider these changes to be necessary to ensure consistency with the policy intent and to address divergent practices observed under RIIO-2. The revised definitions are designed to align more closely with actual tax treatment and to ensure that tax relief and clawback are appropriately matched. We will ensure that the final drafting of the TDNI definition includes appropriate wording to avoid any risk of double-counting.

7.17 We also note concerns raised regarding the inclusion of interest disallowed under the Corporate Interest Restriction (CIR) rules within the TDNI definition. We consider that including such amounts is appropriate, as CIR is a group-level restriction that may be temporary and subject to reallocation. Excluding such amounts could create incentives for licensees to structure disallowances in a way that reduces clawback and introduces an additional risk of manipulation insofar as the allocation might be unwound subsequently by licensees.

Tax Clawback Methodology - Inflation Accretion

Background

7.18 At SSMD we decided to amend the definition of Adjusted Net Debt for the Tax Clawback to specifically include inflation accretion (net of paydown) associated with index-linked derivatives.

Final Determinations decision

7.19 We are implementing this amendment (with unchanged rationale) having also consulted on it in our Draft Determinations.

7.20 In its business plan submission, and in its response to the Tax Clawback Call for Input, WWU restated its view that RPI swap interest accretion should not be included within Net Debt, as in its view this creates an inconsistency of treatment between the cost of debt allowance and the tax clawback. No new evidence was presented in WWU's Draft Determination submissions and WWU did not repeat the argument in detail.

7.21 We therefore consider it reasonable to retain the decision made at SSMD.

Tax Clawback Methodology - calculation of excess interest

Final Determinations decision

7.22 We are maintaining our methodology from RIIO-2.

Stakeholder responses and rationale

7.23 WWU has, within its SSMC response, business plan and response to the Tax Clawback Call for Input, restated its view that the calculation of excess interest within the tax clawback is disproportionate. It seeks to characterise this as an 'error' and proposes that excess interest be calculated by pro-rating the interest cost by the proportionate over-gearing.

7.24 No further evidence has been provided by WWU, other than stating that it disagrees with our response and that small increases to gearing above the excess level would not result in higher credit spreads.

7.25 Within its Draft Determinations response, WWU has reiterated its arguments in respect of its position that the current gearing test represents an unfair 'cliff-edge' and that a form of pro-rating should be used instead. Within its Draft Determinations response it has proposed an alternative mechanism whereby pro-rating would take place if gearing had been under the threshold in the previous year, and did not exceed 65%.

7.26 The proposed change to the tax clawback put forward by WWU would result in licensees with small amounts of excess interest having their tax allowance reduced by an amount greater than the tax benefit received from the excess interest. This effect can be seen in Example B in Table 24. The proposed change would also result in licensees with significant amounts of excess interest retaining the vast majority of the tax benefit arising from excess interest. This can be seen in Example A in Table 23, where a licensee with £100m of excess interest would

retain the vast majority of the tax benefit arising, being £23.57m of the £25m benefit with only £1.43m being clawed back for consumers. Within the examples in Table 23 illustrative numbers have been used for simplicity.

Table 23: proposed interest clawback calculation (example A):

Example A - £100m excess interest, tax benefit £25m	**WWU proposal**	**Current Method**
Notional interest (A)	250	250
Actual interest (B)	350	350
Notional gearing (C)	60%	60%
Actual gearing (D)	61%	61%
Excess interest:		
WWU proposal ((D-C)/D)*B	5.74	
Existing tax clawback (IF B>A, B-A,0)		100
Reduction in Tax Allowance	1.43	25.00
Reduction in Allowed Revenue	1.91	33.33

Table 24: proposed interest clawback calculation (example B)

Example B - £1m excess interest Tax benefit £0.25m	**WWU proposal**	**Current Method**
Notional interest (A)	250	250
Actual interest (B)	251	251
Notional gearing (C)	60%	60%
Actual gearing (D)	61%	61%
Excess interest:		
WWU proposal ((D-C)/D)*B	4.11	
Existing tax clawback (IF B>A, B-A,0)		1
Reduction in Tax Allowance	1.03	0.25
Reduction in Allowed Revenue	1.37	0.33

7.27 We consider that adopting WWU's methodology for calculating excess interest would result in an excessive restriction of the tax allowance for licensees with small amounts of interest in excess of the notional allowance, as shown in Example B. Adopting a pro-rata approach may, in certain circumstances, create a perverse incentive to over-gear.

7.28 ET licensees will have significantly higher interest costs as a result of increased capex during the RIIO-3 period, and the proposed pro-rata calculation put

forward by WWU would result in an exaggeration of this effect in the later years of the price control. Further, adopting WWU's proposed calculation would result in licensees in different sectors having different amounts of clawback for the same percentage over-gearing and excess interest, due to the different levels of allowable gearing between the sectors.

7.29 We also analysed by how much actual interest would need to exceed notional interest under WWU's methodology to result in a reduction in allowed revenue which could be considered material. We used the tax trigger deadband levels set in the RIIO-3 PCFM as a proxy for what would be considered material. We used the notional interest figures from the RIIO-3 PCFM. We used mean averages of the 5 years of the price control and number of licensees in the sector. Table 25 below shows this as a percentage. As can be seen in the table, at higher gearing levels even actual interest below notional interest would result in a clawback.

Table 25: Proportion of actual interest to notional interest resulting in a reduction in Allowed Revenue matching the deadband under WWU methodology:

Sector	1% excess gearing	2% excess gearing	3% excess gearing	4% excess gearing	5% excess gearing
GD	386%	196%	133%	101%	82%
GT	297%	151%	102%	78%	63%
ET	296%	151%	102%	78%	63%

7.30 As can be seen in the above table under WWU's pro-rata proposal, where excess gearing is low, actual interest costs must significantly exceed the notional costs before a clawback, above the level of the tax trigger event deadband, would occur. In this circumstance licensees would retain significant tax benefits at the expense of consumers. This can be seen in Table 26 below.

Table 26 **-** Tax benefit £m retained by licensee when clawback matches deadband in WWU methodology

Sector	61% actual gearing	62% actual gearing	63% actual gearing	64% actual gearing	65% actual gearing
GD	81.0	25.5	7.0	-2.2	-7.8
GT	130.9	30.6	-2.9	-19.6	-29.6
ET	277.3	54.5	-19.8	-56.9	-79.2

7.31 Licensees ta

7.32 ke out debt and debt-related financial instruments which remain in place for many years. WWU states that we should only consider the additional interest cost which arises in a period where the licensee is overgeared, and that to include

existing higher interest costs is disproportionate. However, this does not account for the fact that the borrowing driving these higher current interest costs may have arisen in previous periods of over-gearing. To only focus on increased costs in the current period of over-gearing would in effect allow licensees to retain the benefit of any past over-gearing.

7.33 We still consider that the gearing test should continue to operate as it has done since it was introduced and consider that it should not change it for RIIO-3. We recognise the concerns raised regarding the binary nature of the gearing threshold. While we do not propose changes to the current approach, we have considered the proportionality of the mechanism and the alternative proposals put forward. We consider the current approach to be a proportionate means of incentivising prudent financial structuring, and note that the AIP provides a route to address any exceptional circumstances.

Tax clawback - other stakeholder responses

7.34 NGET commented within its Draft Determinations response and Tax Clawback CFI response that in its view there is an inconsistency between the PCFM and RFPR with regard to the calculation of actual gearing, with the RFPR using an average position, and the PCFM using the closing position. It advocates that there should be consistency between the two models.

7.35 It also highlights that there can be changes to RAV after the RFPR is submitted, but before the final iteration of the PCFM due to totex forecasting. It suggests applying a tolerance in line with the equity issuance threshold to prevent 'erroneous' triggering. Whilst we note that the equity issuance threshold has been reduced to 0% in RIIO-3 (see 3.59), we would consider this unnecessary. The previous equity issuance threshold would result in a very high threshold compared to other comparators such as the tax trigger deadband. NGET also suggests that licensees should be able to re-forecast ANDt and TDNIt during the AIP process. We consider reforecasting of the values during AIP to be appropriate and will update the relevant guidance in due course. This should mitigate the need for a tolerance as requested by NGET.

8. Regulatory Depreciation

Purpose: Regulatory depreciation rates determine the speed that the RAV is repaid by consumers.

Benefits: Appropriate rates of depreciation help ensure that network charges are fair for both current and future consumers. Depreciation rates can reflect the economic and technical lives of the underlying assets.

Final Determinations summary

Parameter	Final Determination	Draft Determination
GD	For existing assets - retain the sum-of-digits depreciation profile and 45-year asset life assumptions. For new investments - sum-of-digits with investment returned by government's net zero target date (2050).	Same as FD.
GT	Retain the existing sum-of-digits with a 45-year asset life depreciation profile.	Same as FD.
ET	Retain the existing 45-year asset life, straightline depreciation profile.	Same as FD.

GD

Final Determinations decision

8.1 We have decided to implement our Draft Determinations proposal (Option 4), maintaining the existing depreciation profile for RAV outstanding at the end of RIIO-2 New additions to the RAV during RIIO-3 and onwards will be depreciated on a sum-of-digits basis, with the assets depreciated to zero by the government's net zero target date, which is currently 2050.

8.2 We consider that our decision represents a reasonable, balanced approach given our ongoing work with government to consider the future of the gas system. Further detail on our engagement with government's programme of work can be found in Chapter 7 of the Overview Document. We will continue to monitor the appropriateness of this policy throughout RIIO-3, informed by our continued work with government, and will review our approach ahead of RIIO-4, or earlier if necessary.

Stakeholder responses and rationale

Responses to FQ24: What are your views on our proposal to accelerate depreciation for new assets only in GD and is there any further evidence you would like us to consider before we reach a final decision?

8.3 We received 13 direct responses to our Draft Determinations position.

8.4 Of these responses seven were broadly supportive of our Draft Determinations proposal, five were broadly negative, and one was neutral.

8.5 Responses were mixed from the GDNs, with two positive and two negative responses.

8.6 Gas Distribution Networks (GDNs) considered that as a result of the proposed acceleration of depreciation on new assets, dividend yields should be increased from the proposed 3%. We address this issue further in paragraphs 3.98 and 3.99.

8.7 WWU and NGN provided positive responses to the consultation question, both however expressed concerns over asset stranding risk, which is discussed further below.

8.8 Cadent stated that it thinks that any decision to accelerate depreciation is premature. It cited uncertainty over the future decarbonisation pathway as the reason for this. We disagree and consider that our decision is a balanced approach that aligns with government's work on the strategic challenges facing the future of the gas system - including how to recover network investment. More detail on this is provided in Chapter 7 of the Overview Document.

8.9 SGN disagreed with Option 4 and proposed an alternative methodology for calculating accelerated depreciation. We disagree with this approach as we do not think it adequately addresses the risk to future consumers. This is discussed in more detail below.

8.10 We received responses from two of the GDNs' Independent Stakeholder Groups (ISGs). Both ISGs were supportive of the proposed decision. WWU's ISG noted its concern that, absent broader government intervention, rising costs will fall on fewer consumers, who may be the least able to afford to switch from gas. SGN's ISG acknowledged government's upcoming call for evidence on network investment and cost recovery and sought clarity on how this review may influence the RIIO-GD3 settlement. We consider our approach is aligned with government's upcoming call for evidence. We will continue to monitor the appropriateness of

this policy throughout RIIO-3, informed by our continued work with government, and will review our approach ahead of RIIO-4, or earlier, if necessary.

8.11 A consumer group was supportive of our proposal, as was an environmental group, which considered the estimated bill impact to be reasonable.

SGN's proposed methodology

8.12 SGN has proposed an alternative methodology for accelerating depreciation.

8.13 This method of accelerating depreciation, if adopted, would reference actual switching data, to determine the amount of accelerated depreciation in any regulatory year either with, or without, an equalisation factor to smooth the impact. This would link the level of accelerated depreciation to the number of customers who had disconnected from the network two years previously. SGN said its proposal is more appropriate as it would only trigger accelerated depreciation when, and to the extent, it is required. It argued this would be fairer to customers and provide investors with better long-term clarity.

8.14 We do not think SGN's proposed approach adequately addresses the risk to future consumers. Under this method, depreciation would only be accelerated once customer numbers had already declined, leaving fewer consumers to share the fixed network costs and potentially worsening affordability issues. SGN's analysis suggests that our approach would not fully mitigate the long-term risks if continued through future price control periods up to 2050. However, our approach is adaptable and will be reviewed as part of setting RIIO-4, or sooner if appropriate, considering the outcomes of the government-led future of gas programme.

8.15 We also consider that having a dynamic method of accelerating depreciation could result in variations in Allowable Revenue which could make financial planning more difficult for GDNs. Further, if a dynamic model is used and very low switching occurs in RIIO-3, then little to no mitigation of the asset stranding risk would occur.

8.16 We therefore consider that our decision provides a balanced and more predictable approach. We consider this to better fulfil our statutory duties to protect both current and future consumers, as it limits RAV growth during RIIO-3 to avoid exacerbating an unfair burden of cost recovery on future consumers, fairly accelerates the recovery of the fixed costs when a significant number of consumers remain connected to the network whilst avoiding placing disproportionate pressure on current consumer bills.

Asset stranding risk / RAV recovery

8.17 All of the GDNs, including those who were broadly supportive of our proposal, and four other stakeholders considered that our proposed change to the depreciation policy does not fully mitigate asset stranding risk. They noted the proposed methodology only results in new assets being fully depreciated by 2050, leaving a proportion of the RAV remaining unless further action is taken in future price controls. We consider our decision appropriately mitigates asset stranding risk within RIIO-3.

8.18 We also consider that given the uncertain future use of the gas distribution network and our ongoing work with government to explore alternative long-term solutions to recover network investment (as discussed in Chapter 7 of the Overview Document) which will then inform future decisions on the payback of the RAV.

8.19 SGN called for us to make clear unambiguous statements that our RIIO framework assumes that the RAV will be fully recoverable and that full recovery of RAV and costs cannot be borne by gas customers alone if there is a transition to alternative heating by 2050. It states that this should not be deferred to RIIO-4 or the outcome of the government review. SGN stated that the alternative would be for us to increase the cost of equity by c.1.7%. Similarly, NGN stated that it considers that asset stranding risk should be specifically addressed within the Cost of Equity via beta or an uplift.

8.20 We consider that government's upcoming network cost recovery review is the right place to consider any risks, such as they exist, in the round, and with all other mitigation options. Please also refer to paragraphs 3.46 and 3.49for our consideration of gas asset stranding risks in the cost of equity allowance.

Decommissioning costs

8.21 A supplier and a DNO made broader points in their responses that they consider that the cost of decommissioning the gas distribution network needs to be considered alongside accelerated depreciation.

8.22 We consider that there needs to be further work to understand the cost of potential decommissioning, and how to plan and pay for it. We therefore welcome government's commitment to publish a call for evidence on the operational transition of the gas system in 2026, which we will support.

Other evidence

8.23 Citizens Advice recently published an analysis on the future of gas[64].

8.24 This report draws attention to the costs and potential impact on consumers of customer disconnections and decommissioning of the gas network, along with the impact of accelerated depreciation.

8.25 The report finds that accelerated depreciation would be a relatively small part of unsustainable bills in future periods. It draws attention for the need for clear government policy on the future transition away from gas.

8.26 We consider this report to be supportive of our view that we may need to reconsider accelerated depreciation ahead of RIIO-4 or sooner, if necessary, informed by the outcomes of the government review.

GT

Final Determinations decision

8.27 We have decided to retain the existing sum-of-digits with a 45-year asset life depreciation profile for GT as set out in our Draft Determinations. This is based on the low regret risk of maintaining the existing depreciation policy prior to the completion of the government review, as explained in paragraph 8.46 of the Draft Determination Finance Annex.

8.28 Stakeholder feedback in response to the Draft Determinations was broadly supportive of this approach, or neutral towards it.

Stakeholder responses and rationale

Responses to FQ25: Do you agree with our proposal to maintain the existing depreciation policy for gas transmission assets?

8.29 We received seven direct responses to our Draft Determination position.

8.30 Stakeholders highlighted the need for further clarity in government policy before any action is taken by us. Most agreed with our assumption that GT assets are likely to play a greater role in the post-transition energy system than GD assets. Cadent stated that it does not consider that there is sufficient evidence to validate this assumption.

[64] The Great Grid Switch Off: How to fairly manage the transition away from gas - Citizens Advice

8.31 A consumer group stated that it considers the risk of deferring any changes to GT depreciation until the next price control to be low, given the relatively small proportion of consumer bills which relates to this.

8.32 We consider the need for further clarity justifies maintaining the existing approach to regulatory depreciation and asset lives for GT during the RIIO-3 price control period.

8.33 National Gas commented that we should review the charging methodology during RIIO-3 to look at whether GT charges should be recovered from a broader customer base (i.e. electricity customers). Similar comments were provided by NESO. We agree that alternative long-term solutions should be considered. This should be by both us and government. We will review our approach to GT depreciation when setting RIIO-4, considering the outcomes of the government-led future of gas programme.

ET

Final Determinations decision and rationale

8.34 We have decided to retain the existing 45-year asset life and straight-line depreciation profile. This is based on CEPA's analysis[65] and stakeholder feedback.

Stakeholder responses and rationale

Responses to FQ26: Do you agree with our proposal to maintain the existing depreciation policy for electricity transmission assets?

8.35 We received five substantive responses to our Draft Determination position, including responses from all of the ET network companies.

Depreciation Gap

8.36 Respondents noted the existence of a depreciation 'gap' or 'depreciation holiday'. This describes the knock-on impact on depreciation, and the decision to increase asset lives from 20-years to 45-years in RIIO-1. This change results in a period of lower depreciation, as the older 20-year life assets become fully depreciated. Respondents argued that this represents a 'payment holiday' because current consumers are benefitting from lower depreciation charges at the expense of future consumers.

8.37 SPT and NGET provided reports prepared by NERA calculating the impact of the depreciation gap on their respective networks during the RIIO-3 and future price control periods. SPT's NERA report states that the impact from RIIO-T3 to the

[65] RIIO-ET3: Economic Lives of Electricity Transmission Network Assets

2060's is circa £1.2bn. NGET's NERA report states that the impact from RIIO-T3 to the 2060's is circa £7.2bn.

8.38 Respondents noted that longer depreciation lives result in the RAV remaining higher for longer, thus increasing overall RAV return. We consider that this represents an appropriate allocation of depreciation and return, as the RAV depreciation and return are then aligned broadly with the use of those assets.

8.39 Eon responded that it considers that maintaining the current approach will limit the impact of higher capex in RIIO-3 on current customers. It also considers that the approach fairly shares costs between current and future customers.

Useful Economic Lives

8.40 SHET has stated that it considers that the 45-year asset life should be reduced for new assets to 35 years. It highlights the increased levels of offshore and near-shore assets within its capex programs for the RIIO-3 period, along with increased spend on software and electronic assets. It also provided example assets from its Business Plan, that show significantly shorter asset lives for offshore assets, and data showing that asset lives decrease with geographical proximity to the shore.

8.41 We consider it is still appropriate to retain a single RAV for both existing and new assets, with a single 45-year life. As stated in the previously published CEPA report, even with increased spend on offshore assets in RIIO-3, the overall proportion relative to the existing RAV does not result in a significantly reduced overall asset life.

8.42 SHET also noted financeability concerns regarding pressure on metrics, particularly in the RIIO-4 period, and advocate reducing asset lives in RIIO-3 to proactively manage this risk. Our decisions in this chapter have been considered as part of our financeability assessment support a financeable package (with further detail set out in chapter 5). We will separately consider any necessary measures to improve the future financial metrics of the ET network companies.

9. Return on Regulated Equity (RoRE) and Return Adjustment Mechanisms (RAMs)

Purpose: The purpose of RoRE is to allow effective comparison of earnings potential outcomes across companies. The purpose of RAMs is to provide protection to consumers and investors in the event that network company returns are significantly higher or lower than anticipated at the time of setting the price control.

Benefits: Consumers and investors benefit from RAMs as they are protected against the possibility of unreasonably high or low returns. RAMs will help to ensure the fairness of RIIO-3 by protecting consumers and investors against ex post overall returns deviating greatly from ex ante expectations.

Final Determinations summary

Parameter	Final Determinations	Draft Determinations
Primary threshold level	3% plus or minus baseline allowed return on equity.	Same as FD.
Primary adjustment rate	Adjustment of 50% applied to returns above or below the primary threshold level.	Same as FD.
Secondary threshold level	4% plus or minus the baseline return on equity.	Same as FD.
Secondary adjustment rate	Adjustment of 90% applied to returns above or below the primary threshold level.	Same as FD.

Background

9.1 RoRE is a measure of returns earned by equity investors that includes the 'base' allowed return on equity, operational out or underperformance and financing out or underperformance.

9.2 RAMs exist to provide protection to consumers and to investors in situations of extreme operational outperformance or underperformance. We have decided to adopt the RAMs primary and secondary thresholds and adjustment rates as proposed in Draft Determinations and also to include ASTI projects within the RAMs.

Thresholds and adjustment rates

Final Determinations decision

9.3 We have decided to maintain our thresholds and adjustment rates as proposed at Draft Determinations.

Stakeholder responses and rationale

Responses to FQ27: Do you agree with our proposals for the RAM thresholds and adjustment rates?

9.4 Three respondents supported the retention of the primary and secondary thresholds and the adjustment rates as we proposed in Draft Determinations. NGET told us that narrower thresholds would risk damaging the incentive properties of other parts of the regulatory framework and broader thresholds would offer less protection to consumers and investors. SPT told us it was broadly comfortable with the continuation of the RIIO-2 RAM thresholds and adjustment rates. National Gas said that given the operation of the RAM thresholds throughout RIIO-2 it did not see a robust case for change in this area. We agree with these three respondents and would highlight the points that narrower thresholds risk damaging the incentive properties of the price controls and wider thresholds carry greater risk of harm to consumers or investors. The evidence we have from RIIO-2 so far seems to suggest that the RAMs will not be triggered. As RAMs are only intended to be triggered in the event of a fundamental miscalibration of the price control through unforeseen circumstances, this gives us confidence that the overall price control package in RIIO-2 was well calibrated.

9.5 Several licensees were supportive of RAMs but believed that current thresholds should be recalibrated. Cadent suggested that combinations of outperformance or underperformance to reach the primary thresholds for RAMs were so extreme as to be unlikely. They suggested that we should consider moving the thresholds to a lower level which would still only be breached in exceptional circumstances. Cadent supplied us with a report by Economic Insight that showed that, although a RAM could, in theory, be triggered for one of their operating companies, it assumes it would not be triggered because the simple aggregation of risk is not representative of the actual risk Cadent faces. Similarly, SGN commented that it believes the current threshold of 3% seemed significantly beyond what it would consider to be an extreme outcome.

9.6 We have decided not to recalibrate the RAMs primary and secondary thresholds. We consider that the thresholds we have employed in RIIO-2 remain the right ones in terms of balancing the risk profiles that exist for RIIO-3 in terms of what

is extreme. The RAM is intended as a fail-safe mechanism which should only be triggered in the event of circumstances which were unforeseen at the start of the price control. We agree with some respondents that tighter thresholds risks interacting with other parts of the price control (such as ODIs) in unforeseen ways.

9.7 The network licensees that rejected the use of RAMs entirely argued that they were unnecessary if the other incentive mechanisms in the price control were well calibrated. They cited the danger of too narrow a calibration of performance bands which would disincentivise good performance and expose investors to greater risks. SHET said that RAMs introduced unnecessary regulatory complexity and NGN added that this risks harming consumers in the longer term. NGN noted that the RAMs risks dampening licensees' incentives to make further efficiencies beyond the threshold and that RAMs transfer risks to customers in the event of underperformance. We do not agree that RAMs are unnecessary. The experience of RIIO-1 outperformance showed that if economic conditions were significantly different than what had been expected at the time the price control was set, the licensees could markedly outperform. As there were no RAMs in RIIO-1, this was to the detriment of consumers. Similarly, the reverse circumstances could apply, leading to extreme underperformance that would require protection for investors. As we show below, our modelling suggests that RAMs will only be triggered under extreme circumstances, and thus the risk of unintended disincentive effects due to interactions with other parts of the price control is minimised.

9.8 WWU supported the retention of RAMs but said that financial and tax performance should be included in the RAMs because this basis would be more relevant to debt and equity investors in the company. NPg commented that including financial performance in the RAM risked "introducing debt sharing by the back door". We do not agree with WWU that financial and tax performance should be included in the RAM. The intent of the RAM is to protect consumers and investors from extreme conditions in the operating environment of licensees, which were not foreseen at the time the price control was set. The consequences of financial decisions are the responsibility of the company and its investors, not consumers. We agree with NPg that including financial performance in the RAM risks creating a risk sharing on gearing between investors and consumers, which does not serve our intention to balance the protection of both groups.

Threshold levels

9.9 To inform our RAMs threshold calibration, we have assessed the business plans and considered the total RIIO-3 package in the round, including calibration of the cost of equity, the size of the ODI package including baseline target setting, and the calibration of the TIM.

9.10 The figures below demonstrate that neither the GD nor the GT sectors are forecast to breach the proposed RAMs thresholds for their sectors in the course of RIIO-3. As in RIIO-2, it is our intention that RAMs are only to be triggered in exceptional circumstances.

Figure 2: Illustrative RoRE ranges, RIIO-GT3 average

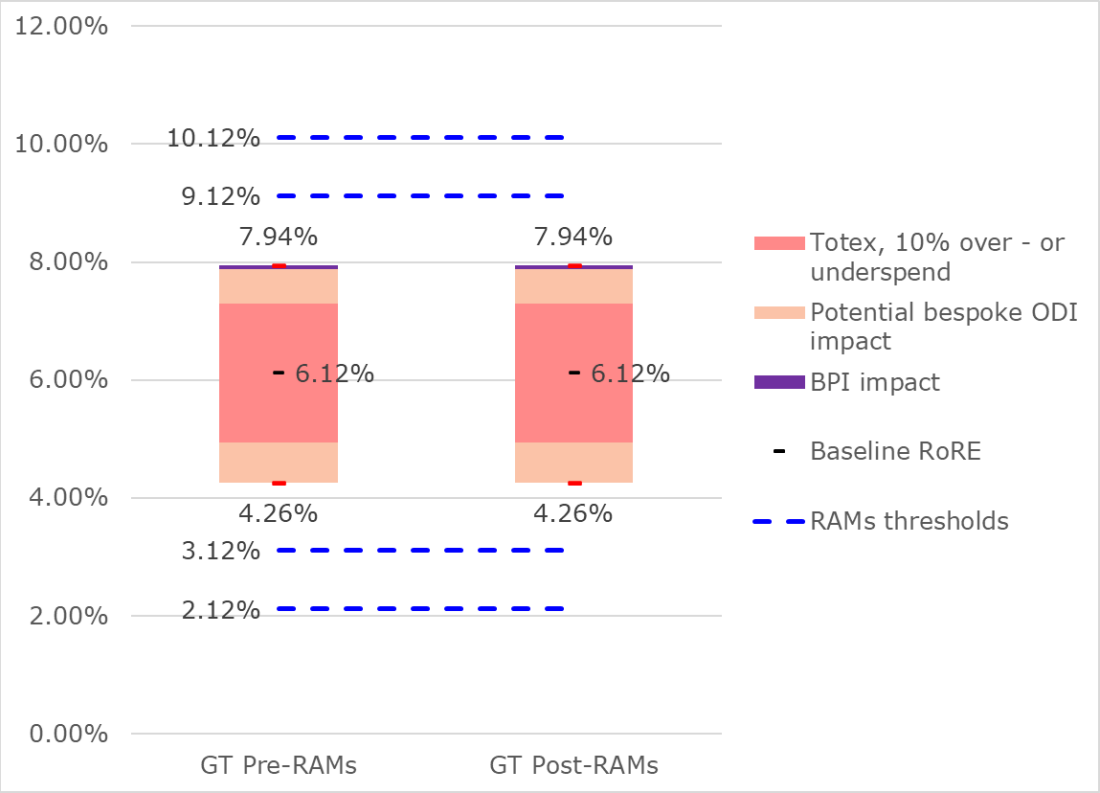
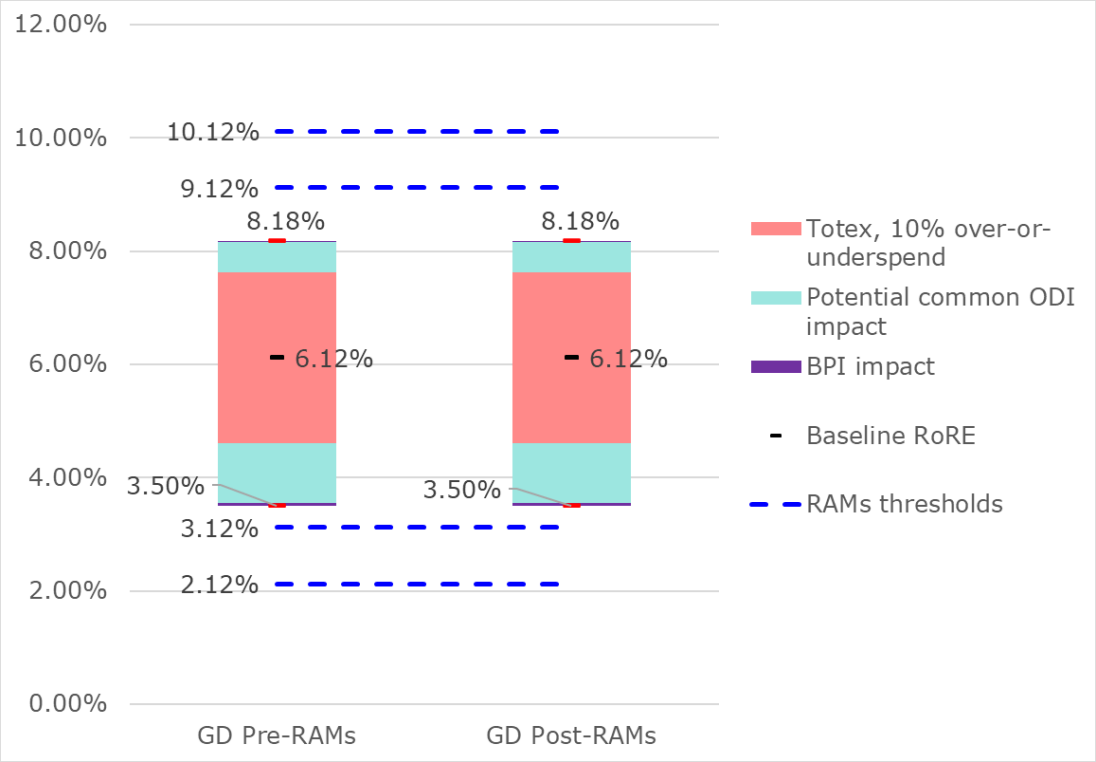
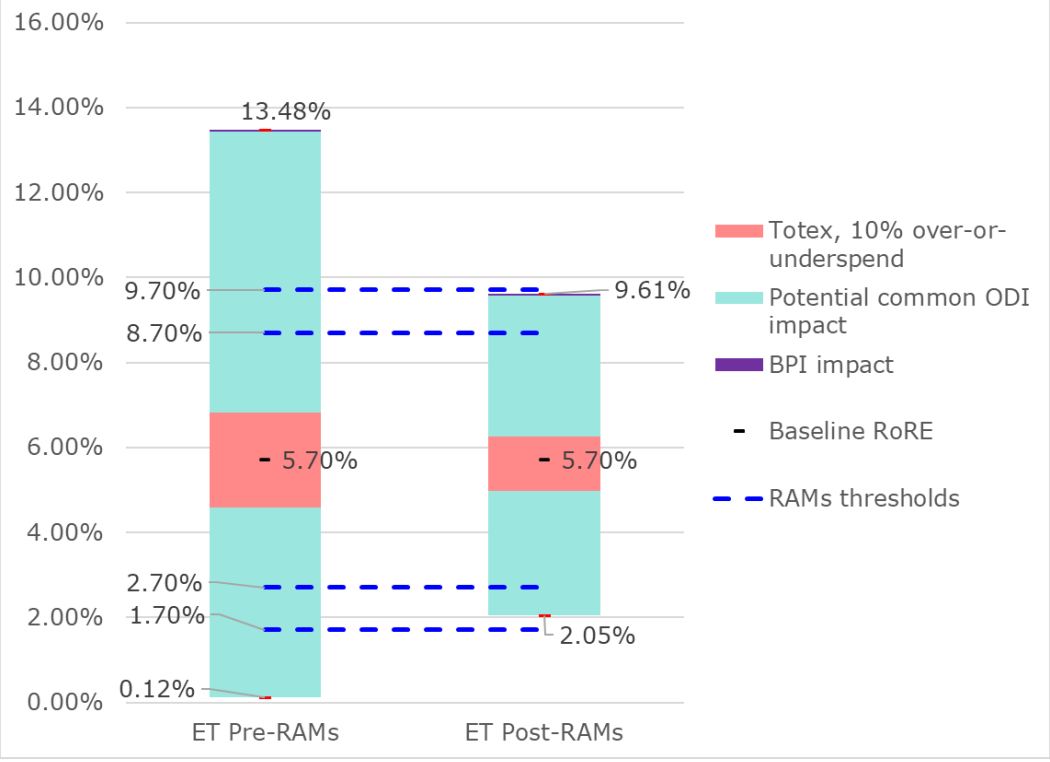


Figure 3: Illustrative RoRE ranges, RIIO-GD3 average



9.11 In the case of the ET sector, there is a wider dispersion of potential outcomes. This is due to the large totex programmes and our decision (see below) to include ASTI within the RAMs.

Figure 4: Illustrative RoRE ranges, RIIO-ET3 average



9.12 If all ODIs are achieved or conversely all penalties are incurred for ET companies, then it is possible that the RAMs would be triggered. Such a combination of high totex underspend and all ODIs earned, or totex overspend and penalties incurred, is in our judgement, unlikely. In these extreme scenarios, the triggering of RAMs will have achieved our policy intent by allowing consumers a greater share of the rewards of extreme outperformance and conversely protecting investors in the case of extreme underperformance.

Adjustment rates

9.13 We did not receive specific comments on the primary and secondary adjustment rates. We decided to retain the proposed rates of 50% and 90%. Our basic approach was to, as we do in other parts of the price control, take a stepped approach to setting adjustment rates. The rates we chose strike a balance, in our judgement, between the company and consumers. A company will still be incentivised to perform better in situations of outperformance or underperformance because the adjustment rates do not serve as a cap and floor (or collar) on returns. Conversely, they protect consumers from risks of excessive returns and investors from downside returns which are significantly below what we envisage at the start of the Price Control.

ASTI and RAMs

Background

9.14 In the Draft Determinations we discussed whether to include a separate RAMs for discrete programmes such as the Accelerated Strategic Transmission Investment (ASTI) framework. Our view was that in setting a separate RAMs for ASTI we would not allow investors to assess company investability in the round. By including ASTI, investors would have a more transparent view of the likely range of returns for ET companies. We considered that lower uncertainty for investors would lead to a lower cost of capital which would in turn benefit consumers.

Final determinations decision

9.15 We have decided to include projects under the ASTI framework within the wider RAMs.

Stakeholder responses and rationale

Responses to FQ28: Do you agree with our proposal to include programmes such as ASTI within RAMs?

9.16 There were five respondents: the three ET companies, Cadent and NPg, an ED company. Three respondents were in favour of including ASTI performance in the

RAMs mechanism. NGET said that the introduction of a separate RAM for ASTI would make the price control more complex. They agreed with us that including ASTI within RAMs supported investability and ultimately benefited consumers. SPT said it was broadly comfortable with the inclusion of ASTI programmes within RAMs. NPg said that if a RAM were to be implemented, it did not think it would be logical to do this while excluding operational and cost performance on a substantial part of the price control settlement.

9.17 SHET was opposed to the inclusion of ASTI within RAMs. It said that ASTI projects were highly complex with significant risk of cost escalation and potential supply chain challenges. Thus, ASTI related expenditure could disproportionately influence RAMs outcomes, increasing the likelihood of breaching thresholds and introducing greater uncertainty. It argued that ASTI projects are already subject to timing delay penalties which would result in a double impact if these were also captured under the RAMs. Cadent made similar arguments about the disproportionate impact of including a large value strategic programme of work on the RAMs. It argued that therefore such programmes should include their own mechanisms to protect customers and companies from material deviations from expected spending.

9.18 We recognise the issues that SHET and Cadent raised with regard to the impact of ASTI projects on overall performance which could be captured by the RAMs. We acknowledge that the incorporation of ASTI projects within RAMs means that there is a greater spread of possible outcomes and therefore of triggering the RAMs. Nonetheless, in our view, there would be greater risks if we did not include ASTI projects within the RAMs. To not include them would complicate the incentives for performance and risk undermining the incentive mechanisms of the price control. If the RAMs are triggered due to ASTI-related performance, then that is as we intend the mechanism to work i.e. as a safeguard mechanism for consumers and investors in the case of operational under or outperformance that could not be anticipated in the setting of the price control. In the interests of transparency and simplicity for investors and other stakeholders, we therefore have included ASTI within the RAMs.

10. Revenue profiling

Purpose:	To manage the anticipated increase in network charges between RIIO-2 and RIIO-3.
Benefits:	Profiling protects the critical investment needed in RIIO-3, while protecting market stability, particularly in the retail sector for suppliers (with large non-domestic customer bases on fixed contracts) and gas shippers.

Background

10.1 Following on from the publication of Draft Determinations, we have considered stakeholder feedback on the potential impact of increases in network revenue allowances on the non-domestic supply market. Non-domestic customers can enter into longer term fixed contracts with suppliers to give them both predictability and certainty over their costs. In turn, large subsequent increases in network charges can affect the stability of the market (for example, higher costs being passed on to non-domestic customers).

10.2 The step-increase in the network cost element of energy bills forecast between 2025/26 and 2026/27 has been a particular focus in feedback. Several stakeholders (Centrica, Octopus, SHET, Sustainability First, I&C Shippers and Suppliers (ICoSS) Group) recommended that we further consider the impacts on non-domestic consumers.

10.3 Complementing our analysis of non-domestic consumers in the Impact Assessment, we consider here how our RIIO-3 allowed revenues can be adjusted to help promote stability beyond networks.

Final Determination decision and rationale

10.4 To mitigate adverse impacts on non-domestic energy consumers, we have decided to implement a profiling of RIIO-3 revenue allowances across ET, GT and GD. We have proposed and modelled adjustments at a sector level for Final Determinations, and will confirm the exact values on a licensee basis in our licence drafting statutory consultation. This is a one-off adjustment being applied within the RIIO-3 period.

10.5 Our Impact Assessment (chapter 5) has further details on the rationale for the profiling adjustments).

10.6 We have decided to 'smooth' the impact of the anticipated increase in 26/27 charges. We have reduced revenues in 26/27, by a smaller amount in 27/28, with offsetting increases in the later years in the period.

10.7 Companies will have flexibility to set the timing and magnitude of the upward adjustments in order to manage revenue volatility, subject to agreement with Ofgem. The downward adjustments will accrue Time Value of Money (TVOM) uplifts such that the overall adjustments across RIIO-3 are neutral on a net present value basis.

10.8 This intervention does not affect other elements of network revenue allowances, such as the tax allowance or equity issuance cost allowance. However, for modelling the effect of revenue profiling on notional company financeability, we have taken into consideration the effect of the adjustments on notional company net debt (see paragraph 5.20 above).

10.9 In practice revenue profiling may have a marginal effect on companies' debt levels. We will ensure that revenue profiling adjustments are netted off and removed from calculations of tax clawback adjustments during RIIO-3.

11. Indexation of Regulatory Asset Value

Purpose: The price controls offer inflation protection to equity investors through inflation adjustments to the RAV.

Benefits: An appropriate indexation mechanism improves legitimacy and fairness for consumers and investors.

Final Determinations summary

Parameter	Final Determinations	Draft Determinations
Indexation of RAV	Apply indexation of the RAV while delinking a portion of the RAV corresponding to the notionally assumed level of fixed-rate debt.	Same as FD.

Background

11.1 The RIIO price controls offer inflation protection to equity investors through inflation adjustments to the RAV. Whilst in RIIO-2 the entire RAV was indexed to CPIH, we proposed for RIIO-3 adopting a nominal allowance for fixed-rate debt in line with the notional capital structure.

Final Determinations decision

11.2 We have decided to implement the approach described in Draft Determinations. By de-linking the notional capital structure's fixed rate debt from inflation and providing a nominal allowance for fixed rate debt instead, we can ensure that investors are not compensated twice for inflation.

Stakeholder responses and rationale

Reponses to FQ29: Do you agree with our proposals for RAV Indexation?

11.3 We received nine responses on our Draft Determinations position on this, all of which were supportive of the proposal.

11.4 SPT and Cadent both suggested that broader assessments should be conducted to consider long-term impacts and the potential for unanticipated consequences. We conducted long-term analysis when developing the proposal, however we agree with the principle of ongoing monitoring.

12. Other Finance Issues

Capitalisation rates

Purpose: Capitalisation rates determine the proportion of costs added to the RAV, with the remainder recovered within the year incurred.

Benefits: Appropriate rates help balance charges fairly between existing and future consumers, whilst also ensuring that networks can meet the costs they face in the near term.

Final Determinations summary

Parameter	Final Determinations	Draft Determinations
Use of two buckets	Fix capitalisation rates ex ante with the same rate applicable in all years of the price control.	Same as FD.
Principle for setting capitalisation rates	Set rates to reflect licensees' expected natural capitalisation during RIIO-3, aiming for consistency within sectors. Adjustments may be made to support financeability.	Same as FD.
Capitalisation rates used for Bucket 1 expenditure	Bucket 1 rates are company-specific.	Same as FD.
Capitalisation rates used for Bucket 2 expenditure	Bucket 2 rates are sector-specific (uniform).	Same as FD.

Background

12.1 Capitalisation rates are the proportion of costs added to the RAV and paid by consumers over time (slow money) rather than paid within the year incurred (fast money).

12.2 In general, the regulatory capitalisation rate broadly reflects the split of capital expenditure (capex) and operating expenditure (opex) expected over the price control, referred to as the "natural" rate.

12.3 In RIIO-2, we implemented two capitalisation rate "buckets": one for ex ante allowed totex (rate one/Bucket 1) and one for re-openers and volume drivers (rate two/Bucket 2). Bucket 1 rates were set bespoke for each company, whilst Bucket 2 rates were uniform within each sector. These two buckets are fixed ex ante for the price control period and let the overall capitalisation rate to change as additional re-opener funding is allowed.

12.4 In RIIO-3, all ET and GT UMs other than re-openers are assigned to Bucket 1. For GD all UMs other than UIOLI and re-openers are assigned to Bucket 1.

Final Determination decision

12.5 The applicable RIIO-3 capitalisation rates for Bucket 1 and Bucket 2 for ET, GT and GD are shown below in Table 27, Table 28 and Table 29, respectively.

Table 27: Totex capitalisation rates for RIIO-3 compared with RIIO-2 for the ET sector

Licensee	Bucket 1 (RIIO-3)	Bucket 2 (RIIO-3)	Bucket 1 (RIIO-2)	Bucket 2 (RIIO-2)
SHET	55%	85%	77%	85%
SPT	54%	85%	84%	85%
NGET	53%	85%	78%	85%

Table 28: Totex capitalisation rates for RIIO-3 compared with RIIO-2 for the GT sector

Licensee	Bucket 1 (RIIO-3)	Bucket 2 (RIIO-3)	Bucket 1 (RIIO-2)	Bucket 2 (RIIO-2)
National Gas (TO)	59%	90%	65%	75%
National Gas (SO)	41%	N/A	34%	N/A

Table 29: Totex capitalisation rates for RIIO-3 compared with RIIO-2 for the GD sector

Licensee	Bucket 1 (RIIO-3)	Bucket 2 (RIIO-3)	Repex (RIIO-3)	Bucket 1 (RIIO-2)	Bucket 2 (RIIO-2)	Repex (RIIO-2)
East	29%	70%	100%	29%	70%	100%
London	20%	70%	100%	20%	70%	100%
North West	25%	70%	100%	27%	70%	100%
West Midlands	25%	70%	100%	25%	70%	100%
Northern	28%	70%	100%	34%	70%	100%
Scotland	31%	70%	100%	41%	70%	100%
Southern	31%	70%	100%	33%	70%	100%
Wales & West	29%	70%	100%	31%	70%	100%

12.6 For ET, Bucket 1 rates were broadly aligned with licensees' submitted natural rates. We have decided on a Bucket 2 rate of 85% to address financeability challenges. This is discussed in Chapter 5.

12.7 For GT, the proposed capitalisation rates broadly aligned with the licensees' submitted natural rates in the business plan submissions. National Gas proposed a 90% capitalisation rate for Bucket 2, which we consider appropriate.

12.8 For GD, we have not identified any material changes to the composition of re-openers (Bucket 2) that would warrant a revision to the capitalisation rates established under RIIO-2. Accordingly, the existing Bucket 2 rate of 70% remains appropriate and will be retained in RIIO-3.

12.9 Based on totex allowances at Final Determinations, the aggregate capitalisation rates are broadly comparable to those under RIIO-2. All sectors' projected aggregate capitalisation rates are within 5% of current RIIO-2 out-turn rates.

Stakeholder responses and rationale

Responses to FQ30: Is there any additional evidence we should consider to improve our setting of regulatory capitalisation rates?

12.10 We received nine responses to our consultation on capitalisation rates. Of these:

- Five companies agreed with our proposed approach: NGET, Cadent, NGN, WWU, and NPg
- One company broadly agreed: SGN
- Three companies disagreed: SHET, SPT, and National Gas

12.11 Companies who supported our proposal endorsed the methodology of aligning capitalisation rates with the anticipated division between capital and operating expenditure over the price control period, based on the average "natural" capitalisation rate. This approach was seen as fair and transparent, ensuring that consumer charges reflect actual expenditure over time and promoting intergenerational equity.

12.12 SGN welcomed the alignment of ex ante capitalisation rates (Bucket 1) with natural rates but raised concerns about maintaining this alignment throughout RIIO-GD3. SGN recommended adopting outturn capitalisation rates to avoid adverse impacts on forecast cashflow and credit rating metrics. SGN also highlighted challenges with re-opener and volume driver funding (Bucket 2), suggesting that capitalisation rates should be initially based on forecast totex but adjusted for actual outturns. SGN emphasised the need for more robust disaggregation of totex allowances to ensure accuracy and mitigate financial risks.

12.13 SHET opposed our proposal, stating that it requires an uncertainty mechanism (UM) capitalisation rate of no greater than 82.5% and an aggregated rate of no

greater than 80% to support financeability. SHET noted that it is currently has the highest aggregated capitalisation rate among the TOs, despite having the largest delivery plan relative to its existing asset base. SHET urged us to rectify this disparity by reducing SHET's aggregated capitalisation rate to 80%.

12.14 We note that, based on the Final Determinations cost assessment, SHET's aggregated capitalisation rate is 80%.

12.15 SPT challenged our proposal, arguing that the proposed adjustments to capitalisation rates in RIIO-3 do not address the issue of depreciation under-recovery and instead defer it to future reviews. SPT expressed concern that the front-loading of fast money in RIIO-3 (and potentially RIIO-4) could worsen long-term financeability by reducing further additions into the RAV and therefore depressing depreciation. SPT called for an enduring solution to address the depreciation gap and its impact on financial sustainability.

12.16 In our discussion on financeability (see paragraph 5.53) we discuss the choice between capitalisation rate setting and depreciation and asset lives. We consider that depreciation policy changes can have limited short-term impact whilst potentially introducing longer-term risks. We have set out our decisions and rationales on financeability and depreciation in chapters 5 and 8 respectively.

12.17 National Gas disagreed with our proposal to set capitalisation rates at 100% for UMs, stating that this does not align with established regulatory principles. National Gas supported maintaining alignment with the natural capitalisation rate inherent in the agreed business plan, which we appear to have adopted for baseline totex. National Gas argued that a 100% rate implies no incremental non-capex costs, which is inconsistent with experience from RIIO-2. National Gas recommended retaining the opex escalator for relevant projects and proposed a single capitalisation rate for UMs across RIIO-3, based on a natural rate of approximately 90% derived from their business plan. After careful consideration of National Gas' representations we agree that a 90% capitalisation rate for Bucket 2 is appropriate.

RIIO-2 close out

Purpose:	To ensure the accuracy of opening balances at the start of RIIO-3 and that any items not settled by the end of RIIO-2 are captured in RIIO-3 allowances.
Benefits:	The opening RAV balance and historical RAV additions, along with fast money, drives a number of the building blocks of allowed revenue (depreciation,

return on RAV) and so will need to be correctly set to ensure the accuracy of allowed revenues in RIIO-3.

Background

12.18 There are several areas within the price controls that need to be settled once the price control has ended and outturn data becomes known. These include things such as UMs, incentives and the final RIIO-2 allowed revenue correction adjustments (the Kt and ADJt terms) from the RIIO-2 PCFM. Close out adjustments can be either positive or negative and will be made through either an adjustment to allowed revenue or an adjustment to RAV and closing tax balances.

Final Determinations decision

12.19 We have decided to use a modified version of the existing RIIO-2 PCFM, which will be known as the "RIIO-2 legacy PCFM" to calculate both the legacy adjustments to revenue and the closing RAV balances and closing tax balances for RIIO-2.

RAV opening balances

Purpose: To ensure the accuracy of opening balances at the start of RIIO-3.

Benefits: The opening RAV balance drives a number of the building blocks of allowed revenue (depreciation, return on RAV) and so will need to be correctly set to ensure the accuracy of allowed revenues in RIIO-3.

Background

12.20 Companies submitted estimated values for their opening RIIO-3 RAV balances in their business plan financial model submissions. This included actual and forecast information to bridge the time lag between finalising RIIO-2 and the beginning of RIIO-3.

12.21 We have reviewed the reasonableness of the submitted opening RAV balances for the RIIO-3 PCFM, by comparing them against the estimated closing RAV balances in the current RIIO-2 PCFM.

12.22 Once we have received the outturn data for the final two years of RIIO-2, we will settle the final values for "close out" items and similarly, we will settle the final RAV impacts. For now, companies have used estimates to calculate the RAV impact, and this has been factored into the opening RAV balance that they have submitted.

12.23 We will determine the opening RAV balances following the closeout process described above, by inputting the RIIO-2 RAV additions into the RIIO-3 PCFM to generate the correct opening balances. Until the formal close-out of RIIO-2, a forecast will be used for the RIIO-3 opening RAV balances.

12.24 As with RIIO-2, we will make the historical net RAV additions a variable value in the RIIO-3 PCFM and so the value of opening RAV in RIIO-3 will not be finalised until after the close-out of RIIO-2.

12.25 Once the RIIO-2 closing RAV balances are finalised, the effect of any knock-on changes to RIIO-3 allowed revenues will be trued up via the K-correction mechanism, when allowed revenues are recalculated in 2027.

Final Determinations decision

12.26 We have decided forecasting the closing RIIO-2 RAV balances as opening RAV balances for RIIO-3 because final closing balances for RIIO-2 will not be known until we have completed the close-out of the RIIO-2 price controls, which will not take place until after the summer of 2026.

Directly Remunerated Services (DRS)

Purpose: To allow companies to charge their customers directly for certain services.

Benefits: To avoid consumers paying for a service for which the network companies have already been remunerated.

Background

12.27 Directly Remunerated Services (DRS) are specific activities of the network companies that are settled outside of the price control. Companies are allowed to charge their customers directly for certain services performed. For instance, a network company may enter into a commercial agreement with a third party such as a telecoms provider to lease out unused space on its grid infrastructure for the placement of satellite dishes or pylons. The telecoms provider would then pay a rental fee directly to the network company, according to the terms of that agreement. These services are "directly remunerated" by the third party rather than through Ordinary Transportation Charges.

12.28 The policy intent across sectors is to avoid consumers paying for a service for which the network companies have already been remunerated. Moreover, costs associated with these services are paid for directly by the specific party (or parties) requiring the service. As such, these costs should not be factored into the network companies' cost allowances, to avoid double-counting.

12.29 We proposed to continue to use the DRS methodology in place in RIIO-2 as we were satisfied with the operation of this mechanism. We welcomed further evidence and information from stakeholders on considerations such as how DRS can support net zero and the benefit to consumers in allowing network companies to keep a portion of the profit for DRS services when they have no statutory duty to complete the work. The Business plans were silent with regards to this.

12.30 In our SSMD we stated that the issue of the potentially increasing disconnection costs and how they should be treated was highlighted by several stakeholders. We published an open letter[66] in January 2025 in relation to this and are currently reviewing responses and considering whether regulatory change is needed to the current disconnections charging policy.

Final Determinations decision

12.31 We have decided to continue with the RIIO-2 DRS methodology that is in place. We may consider carrying out a broader review of DRS during the RIIO-3 price control period.

Disposal of assets

Purpose: To appropriately incentivise networks to dispose of assets no longer required.

Benefits: Consumers will benefit from receiving a share of the proceeds from the sale of assets no longer required.

Background

12.32 Where network assets are no longer required, network operators may dispose of or relinquish operational control, subject to consent and where this is clearly in consumers' interests. They may also recover from third parties any costs in respect of damage to their network. Some of these transactions can include the disposal of land. Consumers should benefit from receiving a share of the proceeds from the sale of assets no longer required.

12.33 For RIIO-2 it was decided that where an asset is transferred to a company within the licensee group and then subsequently sold to a third party, we may review the final sale to ensure it was undertaken at a fair market price and in the best interests of consumers. Where there was a difference, we would consider whether

[66] Call for Input - Exercising Consumer Choice: A review of the gas disconnections framework

a further adjustment to totex was required. The licensee would be required to inform us promptly of any completed sale to a third party, setting out:

- the amount of the proceeds from the third party
- the factors which the licensee considers account for any difference between the transferred amount and the proceeds from the third party referring in particular to:
  (1) the general movement in market prices of similar assets
  (2) costs incurred by the company in improving or maintaining the asset between the date of transfer and the date of sale to the third party

12.34 It was also decided that where a company has disposed of an asset, we would net the cash proceeds off against totex from the year in which the proceeds occur before it was subject to the TIM. This decision followed a consultation where all eight respondents were in favour of this policy change.

Final Determinations decision

12.35 We are retaining our RIIO-2 approach for the disposal of assets, as set out in our Draft Determinations.

Stakeholder responses and rationale

Responses to FQ31: Do you agree with the approach to maintain the RIIO-2 treatment for disposal of assets?

12.36 We received nine responses from network companies to our Draft Determinations. Seven agreed with our approach to maintain the current treatment fully.

12.37 Two respondents suggested that large scale network asset transfers, such as a transfer of pipelines from the gas network to a hydrogen network should be dealt with on a case-by-case basis.

12.38 Three respondents suggested that a broader review, which covers repurposing, disconnections and decommissioning, is needed.

12.39 We recognise that a separate approach may be needed for large-scale asset disposals (noting for example the expected government decision on the suitability of hydrogen for heating homes in 2026) and we will consider further reviews during the RIIO-3 period and beyond.

12.40 Two respondents noted that our approach did not function effectively in RIIO-2 due to issues between the RRP and the PCFM.

12.41 One respondent stated that our alternative proposal would be NPV negative if the 3.5% societal discount rate is used.

Pension scheme established deficit funding

Purpose: To provide networks a pass-through allowance for funding pension scheme established deficits.

Benefits: Clarification of our existing commitment to provide funding for pension scheme established deficits.

Background

12.42 Our current policy sets a commitment to consumer funding of deficits in defined benefit pension schemes, which were generally in existence before the energy network sector was privatised. To reflect this commitment, our price controls provide a form of pass-through funding by consumers of pension scheme established deficits (PSEDs) in respect of those attributable to service before certain specified cut-off dates. We last updated our policy on this in April 2017.[67]

12.43 The allowed revenue that network companies can recover under this policy is reviewed on a triennial basis as a 'reasonableness review'. We recently performed this review and set a new established deficit pension allowance effective from 1 April 2024.[68]

12.44 We also noted that most schemes are now over 90% funded, with some schemes in surplus. We flagged that we consider that this may be an appropriate time to carry out a review of the policy for funding PSEDs and who should bear the relevant risk in the future. Should we decide to proceed with a review, it will be accompanied by a full consultation process. Any outcomes would only be effective from 1 April 2027 at the earliest and we may also consult on the most appropriate date from which any policy changes should be effective.

12.45 In our SSMD, we asked network companies to assume pension allowances for the relevant portion of PSEDs during the RIIO-3 period that reflect the outcome of the triennial review effective 1 April 2024 with no change to existing policy.

Final Determinations decision

12.46 We reaffirm our Draft Determinations position that network companies reflect pension allowances for the relevant portion of PSEDs during the RIIO-3 period

[67] Decision on Ofgem's policy for funding Pension Scheme Established Deficits
[68] Revised pension allowance values and completion of 2023 reasonableness review

that express the outcome of the triennial review effective 1 April 2024 with no change to existing policy.

Transparency through RIIO-3 reporting

Purpose: To clarify and reinforce existing reporting requirements in relation to corporate governance.

Benefits: Ensuring compliance with current corporate governance reporting requirements enhances transparency and helps demonstrate the legitimacy of company performance.

Background

12.47 As companies adapt to a variety of challenges over the coming years, most obviously the changes required to help meet net zero targets, maintaining best practice in corporate governance measures is likely to become increasingly important.

12.48 During the development of both RIIO-2 and RIIO-ED2 we identified several areas where we considered there could be improved transparency through reporting. These included:

- Executive pay/ remuneration
- Dividend policy
- Corporate governance and ownership

12.49 Our focus on these issues reflected a recommendation to us from the January 2020 National Audit Office report on electricity networks.[69] This recommended that we should ensure network companies make it clear how much tax they pay; how executives are rewarded and how this links to quality of service for customers, and how dividend policies ensure companies remain sustainable.

12.50 In our RIIO-2 Final Determinations we introduced new reporting requirements for the disclosure of executive remuneration to a similar level to that required for UK-listed public limited companies and publication of sustainable dividend policies. These new reporting requirements were practically introduced via a new section on Corporate Governance, contained within the RIGs and RFPR template.[70]

[69] NAO report - Electricity Networks
[70] Decision on modifications to the Regulatory Financial Performance Reporting (RFPR) template and Regulatory Instructions and Guidance (RIGs) for RIIO-2

12.51 We have a clear expectation that the requirements of the RFPR corporate governance section are met in full and that remuneration and decision making in the interests of consumers and other stakeholders are an integral component of licensees annual reporting.

12.52 In our Draft Determinations, we decided to retain the existing RIIO-2 requirements and reiterate our clear expectation that the requirements of the RFPR corporate governance section are met in full.

Final Determinations decision and rationale

12.53 We maintain our position as set out in Draft Determinations.

Ex ante base revenue and RAV

Purpose: To provide a methodology by which ex ante positions for Business Plan Incentive (BPI), UM materiality thresholds and financial Output Delivery Incentives (ODI-F) caps and collars can be set.

Benefits: Providing certainty in advance around the monetary values for these items.

Background

12.54 An ex ante view of base revenue and the equity portion of RAV is necessary in order to determine the rewards and penalties for the Business Plan Incentive (BPI), and to establish monetary values for re-opener materiality thresholds and financial ODI caps and collars. The ex ante setting of these parameters provides licensees with certainty at the start of the price control.

Final Determinations decision

12.55 Our decision on how ex ante base revenues and RAVs are calculated is broadly in line with proposals discussed in our Draft Determinations. Each licensee's £m parameter values are provided in this section.

12.56 BPI and the re-opener default materiality threshold are initially sized in terms of a percentage of RoRE and a percentage of base revenue respectively. To calculate their corresponding £m values for each licensee, both make use of a subset of ex ante totex allowances that excludes: UMs that are capitalised under bucket 2 capitalisation rate (re-openers and UIOLIs), and additional allowances for real price effects. The only difference between the two is that whilst the BPI totex excludes ongoing efficiency adjustments, the re-opener default materiality threshold totex includes them.

12.57 The BPI financial reward or penalty varies annually in real 2023/24 price terms, reflecting annual variation in the ex ante NPV-neutral equity RAV. The re-opener default materiality threshold is sized based on the average annual ex ante base revenue multiplied by 0.5%, and are also expressed in real prices. Our decisions specific to the use of a 0.5% default materiality threshold are discussed in Chapter 7 of the Overview Document.

12.58 The ODI caps and collars are initially sized in terms of a percentage of RoRE. To calculate their corresponding £m values for each licensee, the totex used is equal to the total totex allowances set at Final Determinations (ie including all UMs, post ongoing efficiency and with real price effects allowances). The caps and collars' RoRE values are then multiplied by ex ante NPV-neutral equity RAV and averaged over the RIIO-3 period to calculate each licensee's £m cap and collar values for each ODI, in real 2023/24 price terms. Details of the caps and collars for each individual incentive can be found in our sector-specific annexes.

Stakeholder responses and rationale

Responses to FQ32 (Do you agree with the proposal for the ex ante base revenue definition we will use to calculate the re-opener materiality thresholds?) and FQ33 (Do you agree with the proposal for how we will set ODI caps and collars at final determinations that are fixed for the duration of RIIO-3?)

12.59 With regards to the ex ante totex used for the re-opener default materiality threshold, we received eight responses, all from network companies. Seven of these responses were supportive or supportive with specific queries, while SHET was opposed.

12.60 Three licensees queried the exclusion of ongoing efficiency adjustments from the totex figure, arguing that ongoing efficiency adjustments are part of the ex ante framework of the price control. We agree with this argument and have modified the ex ante totex for re-opener default materiality threshold to include ongoing efficiency adjustments.

12.61 National Gas supported the ex ante setting of base revenue, but proposed an alternative approach for assessing re-openers that fell below the default materiality threshold. Questions around the design and application of the default materiality threshold are addressed in Chapter 6 of the Overview Document and within the specific re-opener sections (where applicable).

12.62 With regards to the 'full' ex ante totex used for ODI caps and collars, we received seven responses, all from network companies. Six responses were supportive or supportive with specific queries, while SHET was opposed.

12.63 For both of the Draft Determinations consultation questions, SHET argued that ex ante setting does not adequately account for significant uncertainty relating to large re-openers, and proposed setting thresholds based on ex post base revenue. Given all other responses favoured the ex ante approach, we believe that any uncertainty that this would create is a greater disadvantage than the benefits of a more accurate ex post base revenue value.

12.64 The values for BPI reward or penalties at Final Determinations are as follows:

Table 30: Business plan incentive rewards or penalties

Licensee (23/24 prices)	2027	2028	2029	2030	2031
Cadent	£4.9m	£4.9m	£4.9m	£4.9m	£4.9m
NGN	£0.6m	£0.6m	£0.6m	£0.6m	£0.6m
SGN	-£2.6m	-£2.6m	-£2.6m	-£2.6m	-£2.6m
WWU	-£1.4m	-£1.4m	-£1.4m	-£1.4m	-£1.4m
National Gas	£2.0m	£1.9m	£1.9m	£1.9m	£1.8m
NGET	£0.1m	£0.1m	£0.1m	£0.1m	£0.1m
SHET	£1.1m	£1.1m	£1.2m	£1.2m	£1.2m
SPT	£2.5m	£2.5m	£2.5m	£2.5m	£2.5m

12.65 The £m ex ante average annual base revenue values for the purposes of setting UM materiality thresholds are as follows:

Table 31: Ex ante average annual base revenue values for the purposes of setting UM materiality thresholds

Licensee	Annual average ex ante base revenue (23/24 prices)	Default Materiality Threshold (23/24 prices)
Cadent-EoE	£872.2m	£4.4m
Cadent-LDN	£630.4m	£3.2m
Cadent-NW	£592.3m	£3.0m
Cadent-WM	£452.4m	£2.3m
NGN	£599.4m	£3.0m
SGN-SC	£470.3m	£2.4m
SGN-SO	£998.0m	£5.0m
WWU	£622.7m	£3.1m
National Gas	£1120.4m	£5.6m
NGET	£2889.2m	£14.4m
SHET	£1279.5m	£6.4m

Licensee	Annual average ex ante base revenue (23/24 prices)	Default Materiality Threshold (23/24 prices)
SPT	£811.9m	£4.1m

12.66 The table below sets out the average equity portion of NPV neutral RAVs for each network company, which can be used alongside the details in our sector-specific annexes to calculate the £m values of ODI caps and collars.

Table 32: Equity portion of NPV neutral RAVs by network company

Licensee	Average equity portion of NPV RAV (23/24 prices)
Cadent-EoE	£1665.5m
Cadent-LDN	£1234.3m
Cadent-NW	£1153.5m
Cadent-WM	£873.4m
NGN	£1161.0m
SGN-SC	£895.2m
SGN-SO	£2021.2m
WWU	£1178.9m
National Gas	£2945.6
NGET	£12765.0m
SHET	£8465.0m
SPT	£3140.6m

Annual Iteration Process (AIP) and Modelling Issues

Purpose: Provide a process of continuously updating allowed revenue and reporting of regulatory data.

Benefits: Increasing transparency and reducing overall regulatory burden.

Background

12.67 The Annual Iteration Process (AIP) for the PCFM enables annual recalculation of allowed revenue by updating 'PCFM Variable Values', so any changes to inputs such as actual expenditure are reflected in the following year's allowances, rather than waiting until the next price control.

12.68 At each price control, we aim to improve the PCFM's efficiency, simplicity, and flexibility, while recognising that these goals may involve trade-offs.

12.69 The PCFM for RIIO-3 is based substantially on the RIIO-2 version, with only modest incremental changes.

12.70 In RIIO-2, we published a consolidated PCFM after each AIP, with allowed revenue dependent on our direction of the Adjusted Revenue term (ADJRt) under Special Condition 2.1.

12.71 For RIIO-3, responsibility for publishing the PCFM and calculating allowed revenue now sits with licensees, who must publish the model at the point of charge-setting, in line with the licence, PCFH, and PCFM guidance.

12.72 We retain responsibility for the PCFM, the PCFH, the methodologies for updating variable values, and the relevant licence conditions. We will continue to review AIP submissions in line with the process outlined in the PCFM guidance. We will also continue to publish an annual consolidated sector version of the PCFM, following the annual iteration process, incorporating all modifications and updates to variable values.

Final Determinations decision and rationale

12.73 We maintain our position as set out in the Draft Determinations regarding the Annual Iteration Process and licensee self-publication of the PCFM for RIIO-3. The RIIO-3 PCFM is based substantially on the RIIO-2 version, with only minimal incremental changes. This approach continues to support clarity of roles, regulatory transparency, and robust annual revenue setting.

Interest on prior year adjustments

Purpose: The interest rate applied to revenue true ups relating to prior years.

Benefits: A properly calibrated rate of interest enables companies and customers to remain broadly neutral to deviations in cash flow timing.

Background

12.74 The price control's revenue allowances in prior years are trued-up as new information becomes available. There three types of true-ups: historical revisions to PCFM inputs (eg reporting totex underspend and reducing revenue accordingly); incentive or other income which is calculated after the year in which it is 'earned'; and charging error where a licensee collects a different amount to that which it set out to collect.

12.75 An interest rate is applied to these true-ups to make both consumers and companies broadly neutral to deviations in the timing of cash flows. We also refer to this rate as the Time Value of Money increment (TVOM).

Final Determinations decision

12.76 In line with our Draft Determinations, for RIIO-3 true-ups we will use one single interest rate, the nominal WACC. This is a departure from the two rates used in RIIO-2.

Stakeholder responses and rationale

Responses to FQ34: Do you agree with the proposal to move to using nominal WACC as the single uniform TVOM?

12.77 We received nine responses on this, all from network companies. Seven agreed or somewhat agreed with our position, and two responses disagreed.

12.78 Cadent and SGN stated that the RIIO-2 approach of a separate interest rate for revenue true-ups (WACC rate used) versus charging error (SONIA rate) is more appropriate. SPT also considered two rates to be more appropriate, but stated that WACC is the most appropriate rate in the case that just one rate is used.

12.79 Whilst we acknowledge that there are good reasons for retaining the two rates, on balance we believe that simplifying the to a single TVOM is the most suitable arrangement for RIIO-3.

12.80 WWU agreed with the principle of a single rate, but proposed reducing the rate by a fixed percentage to account for the fact the WACC is broadly set using long term rates that may differ from the shorter term of true-ups.

12.81 We favour aligning the rate to the WACC as it is consistent with our general view of the notional companies' cost of capital. This ensure that, on a notional basis, timing effects of true-ups are net present value neutral.

12.82 Licensees that agreed with the question highlighted the benefits of simplifying this area of the price control.

12.83 Our decision brings RIIO-3 into alignment with the TVOM applied for RIIO ED-2. The simplicity of the approach also reduces the possibilities of gaming risk and unintended consequence given that we have decided to use a self-publication approach for RIIO-3 AIPs.

Forecasting penalties

Purpose: To incentivise accurate forecasting for charge-setting and base revenues.

Benefits: Base revenue forecasts feed into the networks' tariffs, which determine consumer bills. Mis-forecasting could result in consumer detriment and a base revenue forecasting penalty would protect against this.

Final Determinations summary

Parameter	Final Determinations	Draft Determinations
Base Revenue Forecasting Penalty components	The base revenue forecasting penalty components are fast money, pass-through, RAV depreciation and return.	Same as FD.
Base Revenue Forecasting Penalty thresholds for GD and GT	Base Revenue Forecasting Penalty thresholds are 8% for GD, 6% for National Gas TO and 12% for National Gas SO.	Same as FD.
Base Revenue Forecasting Penalty thresholds for ET	Base Revenue Forecasting Penalty thresholds increased by +2% points for ETOs compared to Draft Determinations. The thresholds are 8% for NGET, and 10% for both SPT and SHET.	Base Revenue Forecasting Penalty thresholds for ETOs at Draft Determinations were 6% for NGET, and 8% for both SPT and SHET.

Table 33: Final Determinations Base Revenue Forecasting Penalty thresholds

Network	FD Base Revenue Forecasting Penalty thresholds
East	8%
London	8%
North West	8%
West Midlands	8%
Northern	8%
Scotland	8%
Southern	8%
WWU	8%
National Gas TO	6%
National Gas SO	12%
NGET	8%
SHET	10%
SPTL	10%

Background

12.84 Licensees have an annual opportunity to update their variable value forecasts for the remainder of the price control and these forecasts feed into their tariffs and therefore into consumer bills. We think it is therefore reasonable and proportionate to better incentivise accurate forecasting as mis-forecasting would

result in inaccurate bills and potential consumer detriment. While we have a correction mechanism in place through the K correction term, we think it is appropriate to have an additional penal mechanism to provide a stronger incentive for good base revenue forecasting and in RIIO-2 we already had a similar incentive in place for revenue collection errors.

12.85 Notwithstanding the above we recognise that there will sometimes be factors outside of the licensees' reasonable control which might not have been foreseeable at the time of setting its forecasts and for these circumstances, we would apply a waiver.

12.86 We have recently introduced a base revenue forecasting penalty for ED2 and we think there is value in having consistency between sectors, where possible.

12.87 In Draft Determinations we said we examined historical AIP data from the RIIO-2 period and applied a 6% penalty threshold for differences between forecast and outturn base revenues in each period. We found that had such a base revenue forecasting penalty mechanism existed over RIIO-2, it would have been triggered in very few cases. Our analysis did not indicate that penalties would be routine or that there would have been a significant administrative burden resulting from numerous waiver requests as suggested by some companies.

12.88 In Draft Determinations, following engagement with companies and acknowledging certain concerns:

- We proposed amended penalty thresholds for GDNs, SHET, SPT and National Gas SO from our pre-Draft Determinations view of a 6% threshold.
- We proposed increasing the GDNs penalty threshold to 8% to allow for more headroom, particularly in relation to potentially volatile pass-through terms.
- We proposed increasing SHET and SPT's penalty threshold to 8% to allow for more headroom, particularly in relation to the scale of UMs in RIIO-ET3.
- We proposed increasing National Gas SO's penalty threshold to 12% given the National Gas SO's very high proportion of base revenue being fast money and pass-through relative to other licensees.
- We did not propose updating NGET's penalty threshold as it had similar headroom (~20%) to the other ETOs by keeping the penalty threshold at 6%.

12.89 See Table 34 for how the penalty thresholds have been updated during our engagement with licensees.

Table 34: Base Revenue Forecasting Penalty thresholds changes over the price control setting process

Network	Pre-DD BR thresholds	Pre - DD % BR thresholds as proportion of PT + FM	Proposed DD BR thresholds	DD % BR thresholds as proportion of PT + FM	FD BR thresholds	FD % BR thresholds as proportion of PT + FM
East	6%	13%	8%	18%	8%	18%
London	6%	14%	8%	18%	8%	18%
North West	6%	14%	8%	18%	8%	18%
West Midlands	6%	14%	8%	18%	8%	18%
Northern	6%	14%	8%	18%	8%	18%
Scotland	6%	13%	8%	18%	8%	18%
Southern	6%	15%	8%	19%	8%	19%
WWU	6%	13%	8%	18%	8%	18%
National Gas TO	6%	19%	6%	19%	6%	19%
National Gas SO	6%	9%	12%	19%	12%	19%
NGET	6%	16%	6%	16%	8%	22%
SHET	6%	13%	8%	18%	10%	22%
SPT	6%	13%	8%	17%	10%	21%

Table 35 - % Movements of Fast Money and Pass-through required to trigger the penalty

Licensee	BR(£m)	FM (£m)	PT (£m)	FM as % BR	PT as % BR	BR thres-hold %	BR thres-hold £m	Thres-hold BR as % of FM	Thres-hold BR as % of PT	Thres-hold BR as % of FM + PT
East	888	210	189	24%	21%	8%	71	34%	38%	18%
London	641	159	120	25%	40%	8%	51	32%	43%	18%
North West	602	137	126	23%	42%	8%	48	35%	38%	18%
West Midlands	460	109	94	24%	42%	8%	37	34%	39%	18%
Northern	610	133	137	22%	42%	8%	49	37%	36%	18%
Scotland	480	114	103	24%	41%	8%	38	34%	37%	18%
Southern	1012	199	218	20%	38%	8%	81	41%	37%	19%
Wales & West	632	147	138	23%	43%	8%	51	34%	37%	18%
National Gas TO	1203	243	143	20%	28%	6%	72	30%	50%	19%
National Gas SO	134	64	22	47%	64%	12%	16	25%	73%	19%
NGET	4322	1433	152	33%	35%	8%	346	24%	227%	22%
SHET	3012	1264	94	42%	42%	10%	301	24%	320%	22%
SPTL	1221	470	99	39%	44%	10%	122	26%	124%	21%

Final Determinations decision

12.90 Looking at both RIIO-2 actual AIP data and RIIO-3 business plan forecasts, and with reference to our responses and views in the section below, we consider the thresholds (now with +2% points to ETOs' thresholds for Final Determinations), that can be seen above provide a comfortable headroom for routine forecasting errors across all sectors.

12.91 We will also carve out the effects of inflation on base revenue as we agree that this is outside of the licensees' control and we do not want to set a penalty that will result in routine waiver requests.

12.92 Where there are factors that are uncertain or non-controllable we are satisfied that these should still be foreseeable and short-term forecasting should be possible with a reasonable level of accuracy.

12.93 We note, that since Draft Determinations the base revenue, fast money and pass-through numbers have been updated for our Final Determination position. This has resulted in slightly reducing the % movements in pass-through - and therefore pass-through and fast money together - required to trigger the penalty,

given pass-through is a greater proportion of base revenue compared to our view at Draft Determinations. We are aware pass-through is of concern to GDNs, in particular NTS Exit costs and Shrinkage. However, these updated pass-through numbers are primarily driven by large increases in prescribed rates which we consider forecastable. Therefore we consider that despite this movement the thresholds still provide comfortable headroom.

12.94 Where there are unforeseen short-term fluctuations that are outside of the reasonable control of the licensee and are significant enough to breach the penalty threshold for BR from one period to the next, we have a waiver which allows us to waive the penalty by direction. We do not anticipate the penalty being triggered routinely.

12.95 Given the fact there is a large amount of headroom provided by the penalty thresholds, for any waiver request the Authority does receive there will be a high bar for evidence, where the Authority must be satisfied that any instance of under or over-forecasting has been clearly and demonstrably caused by circumstances beyond the licensee's control.

Stakeholder responses and rationale

Responses to FQ35 (Do you agree with the proposed base revenue forecasting penalty mechanism?) and FQ36 (Do you agree that the thresholds have been set appropriately?)

12.96 In the Draft Determinations, we asked two questions about the Base Revenue Forecasting Penalty, FQ35 and FQ36, we address these both below.

12.97 In response to FQ35, nine respondents -the relevant licensees and NPg- either disagreed with the Base Revenue Forecasting Penalty mechanism as a concept or suggested changes to the individual components of base revenue which the penalty applies to. In response to FQ36, eight of nine respondents disagreed with the thresholds proposed unless certain elements, such as pass-through or fast money are removed from the penalty mechanism, and/or suggested increases to the penalty thresholds.

12.98 All nine respondents disagreed that pass-through terms should be included within the base revenue forecasting penalty, due to concerns that this is either non-controllable or non-forecastable for the licensees. GDNs in particular emphasised that they have the highest exposure to pass-through movements given pass-through being a higher proportion of base revenue in comparison to other sectors. GDNs also emphasised that specifically NTS Exit costs and Shrinkage pass-through terms can be volatile due to the fact they are driven by gas prices and demand forecasting.

12.99 On pass-through costs we view the headroom that the thresholds indicate should provide licensees with comfort that the penalty would not be triggered routinely. While these costs may not be non-controllable in their entirety, we are satisfied that they should still be forecastable in the short term given the relative accuracy of licensees forecasting pass-through terms during RIIO-2, particularly when taking into account the headroom provided for by the penalty thresholds. We have therefore not carved these out from the forecasting penalty.

12.100 We note GDNs were particularly concerned with pass-through, especially shrinkage and NTS Exit costs volatility, but the 8% threshold would need a 36%+movement to the overall forecasted pass-through for the regulatory year ahead in order to trigger the penalty. There were no instances of 36%+ movements in overall forecasted pass-through for the regulatory year ahead during the whole of RIIO-2 for GDNs, and on the whole pass-through was relatively accurately forecasted during RIIO-2 for GDNs. We view NTS exit costs and shrinkage as forecastable in the short-term, but note their inherent potential for volatility, driven by unforecastable geopolitical or unpredictable demand-related events, and it is precisely these type of events we would grant a waiver to the penalty for.

12.101 ET companies are by far the least exposed to movements in pass-through due to it forming a small portion of their base revenue. There would have to be 124%+ movements in the forecasted pass-through value in order to trigger the penalty. Given this large amount of headroom, now higher than at Draft Determinations given the increase to the penalty threshold by +2% points for ET companies, and that historically during RIIO-2 they accurately forecasted pass-through we will not be removing PT from the base revenue forecasting penalty for ET companies.

12.102 National Gas TO and National Gas SO have 50% and 73% headroom respectively for movements in pass-through before the penalty is triggered. Looking at historical data from RIIO-2, no such large movements occurred, and as such we consider this is sufficient headroom and we will not be removing PT from the base revenue forecasting penalty for National Gas TO or National Gas SO.

12.103 Eight of the nine respondents disagreed that UMs should be included within the base revenue forecasting penalty, due to concerns that this is either non-controllable or non-forecastable for the licensees, given ultimately these are directed by us. ET companies in particular emphasised the fact that they have the highest exposure to fast money movements given fast money being a higher proportion of base revenue in comparison to other sectors. ET companies emphasised that within RIIO-3 there is an unprecedented magnitude of uncertain

spend through re-openers, especially when compared to RIIO-ED2 where this penalty was also introduced, and as such a like-for-like penalty to ED2 is inappropriate.

12.104 We note the ETOs were particularly concerned with the inclusion of UMs as a part of fast money. We acknowledge the difference between ED2 vs RIIO ET-3, and the large number of UMs in RIIO ET-3, with ETOs being the most exposed to fast money movements compared to other sectors due to fast money forming a higher proportion of base revenue compared to other sectors. However, we consider it is important to keep UMs within the penalty to incentivise accurate forecasting and given their relevance in RIIO-3. We agree with ETOs however, that given the uncertainty in RIIO-3 re-openers, and the historical movements in fast money during RIIO-2 for ETOs, there is a risk if the penalty thresholds are not amended that the base revenue forecasting penalty would be triggered frequently. We have therefore decided to increase the penalty thresholds by +2% points for ETOs in comparison to the thresholds we proposed in Draft Determinations. This threshold increase results in forecasted fast money needing to move by 24%+ (from ~20% in Draft Determinations) in order to trigger the base revenue forecasting penalty. We consider this sets a more appropriate threshold for forecasting movements in the context of RIIO-3 for ETOs. We continue to view UMs as forecastable in the short term for licensees.

12.105 The large difference in penalty thresholds in the ED2 mechanism (6%) the RIIO-ET3 mechanism (8% for NGET, 10% for SHET and SPT) mean that this is not a like-for-like penalty.

12.106 NGET disagreed with its proposed threshold of 6% at Draft Determinations, given we proposed a threshold of 8% for SPT and SHET. We have decided to increase ETO thresholds by +2% points from our Draft Determinations thresholds and NGET now has an 8% threshold. We consider it is appropriate for there to be this difference for NGET given that NGET has a lower proportion of fast money as base revenue compared to SHET and SPTL. From our review of RIIO-2 data we did not find instances of NGET breaching the headroom for fast money that is provided for through the increase to 8% of the penalty threshold.

12.107 Some GDNs were concerned with including UMs in the base revenue forecasting penalty given uncertainty in the GD sector, such as hydrogen. We are comfortable that there is sufficient headroom for GDNs (32%+) for movements in forecasted fast money, before the penalty threshold is reached. We note during RIIO-2 there were no such large movements in forecasted fast money for GDNs.

We view UMs as sufficiently forecastable for the year ahead as we will not be removing UMs from the base revenue forecasting penalty.

12.108 National Gas disagreed with including UMs in the base revenue forecasting penalty as they consider them to be non-controllable and/or non-forecastable. We continue to view UMs as forecastable by National Gas for the regulatory year ahead. We consider there is sufficient headroom for fast money movements before the penalty is triggered given the thresholds of 6% and 12% for the National Gas TO and National Gas SO respectively. We note that looking at RIIO-2 data we did not see movements in fast money beyond the headroom that result from the thresholds that have been decided.

12.109 There were nine respondents to FQ36. Some licensees disagreed with the thresholds proposed given the inclusion of pass-through and UMs within the base revenue forecasting penalty, and suggested higher thresholds if pass-through and UMs were to continue to be a part of the penalty. Per our responses above, we consider there is sufficient headroom with the proposed penalty thresholds whilst including pass-through and UMs for GD and GT. For ET, our view is that there was insufficient headroom and we have therefore increased the penalty thresholds by +2% points for all ETOs compared to the thresholds we proposed at Draft Determinations Following a review of historical RIIO-2 data, and RIIO-3 business plans we do not anticipate the penalty to be triggered routinely.

12.110 Some licensees discussed a potential issue where non-controllable factors could offset controllable forecasting errors resulting in no penalty applied. We acknowledge that this could happen, however the only way to prevent such offsets happening would be to have an individual forecasting penalty per fast money and pass-through variable value, and we consider this to be unnecessarily complex when introducing a new penalty mechanism.

12.111 A couple of licensees mentioned that this penalty would have a downward skew on Return on Regulated Equity (RoRE). Whilst we agree this will form a part of the operational RoRE recorded in the Regulatory Financial Performance Report (RFPR), it is not appropriate for the penalty to impact the RAMs.

12.112 Some licensees requested more clarity or prescription around the waiver process, and had concerns that the process could introduce regulatory burden. We will add further clarity in the licence around timelines of the waiver process. We do not anticipate a material increase in regulatory burden from this waiver process, as we do not expect the penalty to be triggered routinely given the large headroom

that the penalty thresholds allow for. We will monitor the frequency of waiver requests during RIIO-3.

12.113 Some licensees felt that it is not appropriate to introduce the same penalty as ED2, given that ED2 is not equivalent to other sectors. We have acknowledged the differences in sectors by providing for different penalty thresholds in comparison to ED2.

12.114 Some licensees sought clarity as to when the penalty will start from. The penalty will first apply to the forecasted base revenue of regulatory year 2027/28, and as such the penalty would first reduce the allowed revenue for 2028/2029 if it was triggered.

12.115 We view it as very unlikely there would be frequent waiver requests, but we will monitor this during RIIO-3.

Appendices

Appendix 1 – Financial values for the GDNs

A1.1 The figures in these tables do not include revenue profiling adjustments (see Chapter 10 and the Impact Assessment for further detail). The exact profiling amounts will be included in our licence drafting statutory consultation, and will be published in future PCFMs.

Table 36: East of England RAV (£m nominal)

EAST OF ENGLAND	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	4619.8	4720.1	4823.2	4901.5	4974.8	24039.3	4807.9
Inflation	29.6	57.8	57.6	59.2	60.2	264.6	499.5
Net additions (after disposals)	330.6	328.5	327.2	343.9	341.2	1671.4	3012.3
Depreciation	-259.9	-283.3	-306.5	-329.9	-354.9	-1534.6	-2809.2
Closing RAV	4720.1	4823.2	4901.5	4974.8	5021.2	24440.8	44161.5

Table 37: East of England price control revenue (£m, 23/24 prices)

EAST OF ENGLAND	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	232.7	213.5	204.3	207.6	190.8	1048.9	1865.0
Pass-through expenditure	184.3	192.8	191.9	189.1	188.8	946.9	1709.5
Depreciation	237.5	253.5	268.7	283.3	298.6	1341.5	2445.5
Return	216.1	219.4	221.2	223.1	224.5	1104.3	1992.5
Base revenue	870.6	879.1	886.2	903.0	902.7	4441.6	8012.5
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	-	-	-	-	-	-	-
Directly remunerated services adjustment	-	-	-	-	-	-	-

EAST OF ENGLAND	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Cross-subsidy adjustment	-	-	-	-	-	-	-
Business plan incentive	1.5	1.5	1.5	1.5	1.5	7.5	13.5
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	5.0	5.0	5.0	5.0	5.0	25.1	45.1
Calculated revenue (before tax)	877.1	885.6	892.7	909.5	909.2	4474.1	8071.1
Tax allowance	68.3	73.3	80.9	83.0	87.7	393.2	718.2
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	945.4	958.9	973.6	992.5	996.9	4867.3	8789.3

Table 38: London RAV (£m nominal)

LONDON	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	3354.1	3441.9	3543.8	3641.8	3743.5	17725.1	3545.0
Inflation	21.5	42.2	42.4	44.0	45.3	195.4	369.2
Net additions (after disposals)	253.9	265.5	280.8	303.6	336.3	1440.1	2626.4
Depreciation	-187.6	-205.8	-225.1	-245.9	-269.2	-1133.6	-2079.6
Closing RAV	3441.9	3543.8	3641.8	3743.5	3856.0	18227.0	33012.1

Table 39: London price control revenue (£m, 23/24 prices)

LONDON	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	170.5	158.5	155.2	158.3	152.7	795.2	1419.9

LONDON	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Pass-through expenditure	116.5	122.0	121.6	119.8	119.6	599.6	1082.6
Depreciation	171.4	184.1	197.3	211.2	226.4	990.4	1809.5
Return	157.2	160.6	163.4	166.8	170.7	818.7	1480.1
Base revenue	615.6	625.2	637.5	656.1	669.4	3203.9	5792.1
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	-	-	-	-	-	-	-
Directly remunerated services adjustment	-	-	-	-	-	-	-
Cross-subsidy adjustment	-	-	-	-	-	-	-
Business plan incentive	1.1	1.1	1.1	1.1	1.1	5.6	10.0
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	5.0	5.0	5.0	5.0	5.0	25.1	45.1
Calculated revenue (before tax)	621.7	631.4	643.7	662.2	675.5	3234.5	5847.3
Tax allowance	53.1	58.4	63.0	65.7	68.9	309.0	565.0
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	674.8	689.8	706.7	727.9	744.4	3543.5	6412.2

Table 40: North West RAV (£m nominal)

NORTH WEST	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	3234.3	3282.0	3339.8	3387.7	3427.1	16670.8	3334.2
Inflation	20.7	40.2	39.9	40.9	41.5	183.3	345.9

NORTH WEST	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Net additions (after disposals)	209.5	214.6	220.0	226.0	238.1	1108.2	2006.8
Depreciation	-182.6	-197.0	-212.0	-227.6	-243.8	-1062.9	-1943.3
Closing RAV	3282.0	3339.8	3387.7	3427.1	3462.8	16899.3	30516.7

Table 41: North West price control revenue (£m, 23/24 prices)

NORTH WEST	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	141.1	139.6	138.3	135.0	129.8	683.9	1226.6
Pass-through expenditure	122.8	128.4	127.9	126.3	126.1	631.4	1140.0
Depreciation	166.8	176.3	185.8	195.4	205.1	929.4	1692.0
Return	150.8	152.2	153.1	153.9	154.8	764.8	1378.7
Base revenue	581.5	596.5	605.0	610.6	615.8	3009.4	5437.3
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	-	-	-	-	-	-	-
Directly remunerated services adjustment	-	-	-	-	-	-	-
Cross-subsidy adjustment	-	-	-	-	-	-	-
Business plan incentive	1.0	1.0	1.0	1.0	1.0	5.2	9.3
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	5.0	5.0	5.0	5.0	5.0	25.1	45.1
Calculated revenue (before tax)	587.6	602.5	611.1	616.6	621.8	3039.7	5491.8

NORTH WEST	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Tax allowance	51.1	55.0	58.4	59.7	61.6	285.9	520.7
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	638.7	657.6	669.5	676.4	683.4	3325.6	6012.4

Table 42: West Midlands RAV (£m nominal)

WEST MIDLANDS	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	2420.1	2472.2	2528.0	2570.3	2608.5	12599.1	2519.8
Inflation	15.5	30.3	30.2	31.1	31.6	138.7	261.8
Net additions (after disposals)	173.3	174.5	173.5	180.8	193.5	895.6	1617.9
Depreciation	-136.8	-149.0	-161.3	-173.7	-186.8	-807.6	-1478.5
Closing RAV	2472.2	2528.0	2570.3	2608.5	2646.8	12825.7	23179.3

Table 43: West Midlands price control revenue (£m, 23/24 prices)

WEST MIDLANDS	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	118.9	116.2	104.0	104.1	101.9	545.2	971.4
Pass-through expenditure	91.4	95.6	95.2	93.8	93.6	469.6	847.7
Depreciation	125.0	133.3	141.4	149.2	157.2	706.0	1287.0
Return	113.2	114.9	116.0	117.0	118.0	579.1	1045.1
Base revenue	448.5	460.0	456.6	464.0	470.7	2299.8	4151.2
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	-	-	-	-	-	-	-
Directly remunerated services adjustment	-	-	-	-	-	-	-

WEST MIDLANDS	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Cross-subsidy adjustment	-	-	-	-	-	-	-
Business plan incentive	0.8	0.8	0.8	0.8	0.8	3.9	7.1
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	5.0	5.0	5.0	5.0	5.0	25.1	45.1
Calculated revenue (before tax)	454.3	465.8	462.4	469.8	476.5	2328.8	4203.4
Tax allowance	38.6	41.9	43.8	45.9	47.1	217.3	396.0
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	492.9	507.7	506.2	515.7	523.6	2546.1	4599.4

Table 44: Northern RAV (£m nominal)

NORTHERN	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	3198.3	3268.0	3340.0	3415.0	3493.9	16715.2	3343.0
Inflation	20.5	40.1	39.9	41.3	42.3	184.0	347.6
Net additions (after disposals)	227.6	226.5	245.8	266.2	286.6	1252.8	2277.9
Depreciation	-178.5	-194.6	-210.6	-228.6	-248.7	-1061.0	-1943.5
Closing RAV	3268.0	3340.0	3415.0	3493.9	3574.1	17091.0	30914.0

Table 45: Northern price control revenue (£m, 23/24 prices)

NORTHERN	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	142.9	130.5	129.8	130.0	132.8	665.9	1189.0
Pass-through expenditure	144.6	134.5	134.6	136.1	135.8	685.5	1226.4

NORTHERN	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Depreciation	163.1	174.1	184.7	196.3	209.2	927.3	1691.6
Return	149.6	151.9	153.7	156.0	158.7	769.9	1390.3
Base revenue	600.1	590.9	602.7	618.5	636.4	3048.6	5497.2
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	-	-	-	-	-	-	-
Directly remunerated services adjustment	-	-	-	-	-	-	-
Cross-subsidy adjustment	-	-	-	-	-	-	-
Business plan incentive	0.6	0.6	0.6	0.6	0.6	3.0	5.3
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	6.2	6.2	6.2	6.2	6.2	31.0	55.9
Calculated revenue (before tax)	606.9	597.7	609.5	625.3	643.2	3082.6	5558.4
Tax allowance	43.6	49.5	53.3	56.2	60.4	263.0	482.4
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	650.5	647.2	662.8	681.5	703.7	3345.6	6040.7

Table 46: Scotland RAV (£m nominal)

SCOTLAND	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	2513.2	2546.6	2596.3	2634.6	2658.5	12949.3	2589.9
Inflation	16.1	31.2	31.0	31.8	32.2	142.4	268.6

SCOTLAND	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Net additions (after disposals)	159.2	171.4	172.1	169.2	165.6	837.5	1515.8
Depreciation	-141.9	-152.9	-164.9	-177.1	-189.1	-825.8	-1509.7
Closing RAV	2546.6	2596.3	2634.6	2658.5	2667.3	13103.4	23660.1

Table 47: Scotland price control revenue (£m, 23/24 prices)

SCOTLAND	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	114.5	118.7	120.5	111.2	104.5	569.5	1024.6
Pass-through expenditure	95.5	104.4	104.8	105.8	105.6	516.0	936.5
Depreciation	129.7	136.8	144.5	152.1	159.0	722.1	1314.5
Return	117.1	118.2	119.0	119.6	119.6	593.5	1070.0
Base revenue	456.8	478.1	488.8	488.6	488.8	2401.1	4345.5
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	-	-	-	-	-	-	-
Directly remunerated services adjustment	-	-	-	-	-	-	-
Cross-subsidy adjustment	8.2	8.6	9.0	9.5	10.0	45.3	82.5
Business plan incentive	-0.8	-0.8	-0.8	-0.8	-0.8	-4.0	-7.2
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	6.9	6.9	6.9	6.9	6.9	34.5	62.2
Calculated revenue (before tax)	471.1	492.8	504.0	504.2	504.9	2477.0	4482.9

SCOTLAND	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Tax allowance	30.5	32.1	35.1	37.4	40.0	175.0	319.5
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	501.6	524.9	539.0	541.6	544.9	2652.0	4802.4

Table 48: Southern RAV (£m nominal)

SOUTHERN	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	5505.8	5666.7	5835.7	5985.4	6097.9	29091.5	5818.3
Inflation	35.3	69.4	69.7	72.3	73.8	320.6	606.0
Net additions (after disposals)	435.1	440.3	452.6	446.2	446.7	2220.9	4006.6
Depreciation	-309.5	-340.8	-372.7	-406.0	-438.9	-1867.9	-3426.2
Closing RAV	5666.7	5835.7	5985.4	6097.9	6179.5	29765.1	53863.5

Table 49: Southern price control revenue (£m, 23/24 prices)

SOUTHERN	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	220.3	205.3	206.2	187.2	175.8	994.9	1769.5
Pass-through expenditure	203.1	219.5	221.6	223.3	222.8	1090.3	1977.5
Depreciation	282.8	304.9	326.7	348.6	369.2	1632.2	2981.6
Return	258.5	264.4	268.9	272.9	275.8	1340.4	2422.3
Base revenue	964.6	994.1	1023.5	1032.0	1043.6	5057.7	9150.9
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	-	-	-	-	-	-	-
Directly remunerated services adjustment	-	-	-	-	-	-	-

SOUTHERN	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Cross-subsidy adjustment	-	-	-	-	-	-	-
Business plan incentive	-1.8	-1.8	-1.8	-1.8	-1.8	-9.1	-16.4
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	6.9	6.9	6.9	6.9	6.9	34.5	62.2
Calculated revenue (before tax)	969.7	999.2	1028.5	1037.1	1048.7	5083.2	9196.6
Tax allowance	82.2	84.9	92.6	98.0	105.3	462.9	843.7
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	1051.9	1084.0	1121.2	1135.1	1153.9	5546.1	10040.3

Table 50: Wales and West RAV (£m nominal)

WALES AND WEST	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	3212.0	3296.9	3403.9	3488.9	3565.7	16967.4	3393.5
Inflation	20.6	40.4	40.7	42.2	43.2	187.0	353.4
Net additions (after disposals)	245.0	264.8	261.8	271.5	256.9	1300.0	2354.9
Depreciation	-180.7	-198.2	-217.5	-236.7	-257.0	-1090.2	-1999.7
Closing RAV	3296.9	3403.9	3488.9	3565.7	3608.8	17364.2	31431.5

Table 51: Wales and West price control revenue (£m, 23/24 prices)

WALES AND WEST	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	151.9	151.3	148.4	145.9	139.0	736.5	1321.2
Pass-through expenditure	139.9	136.8	137.0	138.2	138.0	689.9	1239.9

WALES AND WEST	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Depreciation	165.1	177.3	190.7	203.3	216.2	952.6	1740.1
Return	150.6	154.0	156.8	159.3	161.2	781.9	1413.1
Base revenue	607.4	619.5	632.9	646.7	654.3	3160.9	5714.3
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	-	-	-	-	-	-	-
Directly remunerated services adjustment	-	-	-	-	-	-	-
Cross-subsidy adjustment	-0.1	-0.1	-0.1	-0.1	-0.1	-0.6	-1.1
Business plan incentive	-1.4	-1.4	-1.4	-1.4	-1.4	-7.0	-12.5
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	7.4	7.4	7.4	7.4	7.4	37.2	67.0
Calculated revenue (before tax)	613.4	625.4	638.9	652.7	660.2	3190.6	5767.7
Tax allowance	25.6	29.0	33.5	37.4	42.4	167.8	310.0
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	639.0	654.4	672.3	690.1	702.6	3358.4	6077.8

Appendix 2 - Financial values for the TOs and National Gas

A2.1 The figures in these tables do not include revenue profiling adjustments (see Chapter 10 and the Impact Assessment for further detail). The exact profiling amounts will be included in our licence drafting statutory consultation, and will be published in future PCFMs.

Table : NGET RAV (£m nominal)

NGET	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	23947.8	26271.7	30142.1	35066.0	40372.7	155800.2	31160.0
Inflation	133.7	280.3	313.7	368.9	425.6	1522.1	2910.6
Net additions (after disposals)	3411.4	4850.9	5929.9	6343.3	6063.9	26599.3	49787.1
Depreciation	-1221.2	-1260.8	-1319.6	-1405.5	-1483.3	-6690.5	-12159.7
Closing RAV	26271.7	30142.1	35066.0	40372.7	45378.8	177231.2	328190.8

Table 52: NGET price control revenue (£m, 23/24 prices)

NGET	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	1173.6	1457.5	1544.7	1539.6	1450.6	7166.1	1433.2
Pass-through expenditure	158.2	145.7	154.3	149.6	152.8	760.7	1363.2
Depreciation	1115.7	1128.0	1156.8	1207.0	1247.7	5855.2	10594.7
Return	1179.4	1323.3	1534.6	1777.9	2013.0	7828.1	14476.8
Base revenue	3626.9	4054.5	4390.4	4674.1	4864.1	21610.0	39593.1
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	30.6	53.4	69.9	71.3	59.3	284.5	538.4
Directly remunerated services adjustment	-205.3	-210.2	-215.2	-218.8	-224.1	-1073.6	-1941.8

NGET	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Business plan incentive	0.1	0.1	0.1	0.1	0.1	0.6	1.0
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	26.6	26.6	23.5	23.5	23.5	123.6	220.7
Calculated revenue (before tax)	3478.9	3924.4	4268.6	4550.2	4723.0	20945.1	38411.3
Tax allowance	39.5	-	-	-	-	39.5	39.5
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	3518.4	3924.4	4268.6	4550.2	4723.0	20984.7	38450.9

Table 53: SHET RAV (£m nominal)

SHET	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	9149.4	13054.1	19013.5	25686.2	30967.2	97870.4	19574.1
Inflation	51.1	139.3	197.9	270.2	326.4	984.9	1918.7
Net additions (after disposals)	4246.8	6310.4	7107.8	5804.8	5697.9	29167.7	54088.6
Depreciation	-393.1	-490.3	-632.9	-794.2	-927.7	-3238.2	-6083.2
Closing RAV	13054.1	19013.5	25686.2	30967.2	36063.8	124784.8	236515.5

Table 54: SHET price control revenue (£m, 23/24 prices)

SHET	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	1043.8	1374.7	1531.6	1248.7	1121.4	6320.2	1264.0
Pass-through expenditure	94.4	94.2	94.2	94.1	94.1	471.0	847.7
Depreciation	359.2	438.7	554.8	682.0	780.3	2815.0	5270.8
Return	533.1	785.0	1104.2	1397.3	1636.1	5455.8	10378.5

SHET	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Base revenue	2030.5	2692.7	3284.9	3422.1	3631.9	15062.0	28093.6
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	73.9	108.1	114.7	79.1	69.3	445.2	816.4
Directly remunerated services adjustment	-21.8	-21.8	-21.8	-21.8	-21.8	-109.0	-196.2
Business plan incentive	1.1	1.1	1.2	1.2	1.2	5.8	10.4
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	5.3	5.1	4.8	4.8	4.8	24.8	44.2
Calculated revenue (before tax)	2089.1	2785.2	3383.7	3485.4	3685.4	15428.7	28768.4
Tax allowance	-	-	-	-	-	-	-
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	2089.1	2785.2	3383.7	3485.4	3685.4	15428.7	28768.4

Table 55: SPT RAV (£m nominal)

SPT	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	5149.5	6215.2	7431.8	8813.9	10266.4	37876.9	7575.4
Inflation	28.7	66.3	77.3	92.7	108.2	373.3	718.0
Net additions (after disposals)	1277.2	1414.0	1595.4	1679.5	1485.8	7451.8	13626.5
Depreciation	-240.2	-263.7	-290.6	-319.7	-352.2	-1466.5	-2692.7
Closing RAV	6215.2	7431.8	8813.9	10266.4	11508.2	44235.6	82255.9

Table 56: SPT price control revenue (£m, 23/24 prices)

SPT	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	489.1	473.5	488.5	475.8	424.4	2351.4	470.3

SPT	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Pass-through expenditure	70.8	82.4	99.3	120.8	121.0	494.3	917.8
Depreciation	219.5	235.9	254.8	274.5	296.3	1281.0	2342.5
Return	272.7	329.6	393.1	461.2	523.2	1979.8	3686.8
Base revenue	1052.2	1121.4	1235.7	1332.3	1364.9	6106.4	11160.7
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	18.2	18.6	20.4	20.1	14.4	91.6	165.1
Directly remunerated services adjustment	-34.4	-37.2	-41.4	-43.9	-47.9	-204.9	-375.4
Business plan incentive	2.5	2.5	2.5	2.5	2.5	12.4	22.4
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	9.5	4.5	4.5	4.5	4.5	27.5	45.5
Calculated revenue (before tax)	1047.9	1109.8	1221.6	1315.4	1338.3	6033.1	11018.3
Tax allowance	-	-	-	-	-	-	-
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	1047.9	1109.8	1221.6	1315.4	1338.3	6033.1	11018.3

Table 57: National Gas-TO RAV (£m nominal)

National Gas-TO	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	7933.4	8195.0	8508.6	8808.9	8912.4	42358.4	8471.7
Inflation	50.9	100.4	101.7	106.4	107.9	467.3	883.8

National Gas-TO	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Net additions (after disposals)	652.4	678.0	686.9	508.8	510.1	3036.2	5420.1
Depreciation	-441.7	-464.8	-488.3	-511.8	-526.9	-2433.4	-4425.1
Closing RAV	8195.0	8508.6	8808.9	8912.4	9003.6	43428.6	78662.2

Table 58: National Gas-TO price control revenue (£m, 23/24 prices)

National Gas-TO	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	247.9	249.7	258.0	223.8	236.5	1215.9	243.2
Pass-through expenditure	135.5	144.0	144.5	145.3	145.9	715.2	1294.9
Depreciation	403.5	415.8	428.1	439.5	443.2	2130.0	3856.6
Return	373.1	383.8	393.9	400.3	402.5	1953.6	3534.0
Base revenue	1160.1	1193.4	1224.4	1208.8	1228.1	6014.7	10869.4
Return adjustment	-	-	-	-	-	-	-
Equity issuance costs	-	-	-	-	-	-	-
Directly remunerated services adjustment	-	-	-	-	-	-	-
Business plan incentive	2.0	1.9	1.9	1.9	1.8	9.5	17.0
Output delivery incentives	-	-	-	-	-	-	-
Other revenue allowance	17.8	8.5	8.4	4.9	4.9	44.6	71.3
Calculated revenue (before tax)	1179.8	1203.8	1234.7	1215.6	1234.8	6068.8	10957.7
Tax allowance	11.6	16.0	23.4	61.1	64.4	176.5	341.3
Tax allowance adjustment	-	-	-	-	-	-	-

National Gas-TO	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Calculated revenue	1191.4	1219.8	1258.2	1276.6	1299.2	6245.2	11299.0

Table 59: National Gas-SO RAV (£m nominal)

National Gas-SO	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Opening RAV	172.0	186.6	215.2	236.3	244.2	1054.2	210.8
Inflation	1.1	2.3	2.6	2.9	3.0	11.8	22.4
Net additions (after disposals)	57.4	71.4	67.3	58.8	60.0	314.9	572.4
Depreciation	-43.9	-45.1	-48.8	-53.7	-57.6	-249.1	-454.3
Closing RAV	186.6	215.2	236.3	244.2	249.5	1131.8	2076.9

Table 60: National Gas-SO price control revenue (£m, 23/24 prices)

National Gas-SO	31 Mar 2027	31 Mar 2028	31 Mar 2029	31 Mar 2030	31 Mar 2031	RIIO-3 Total	RIIO-3 Average
Fast money	75.5	92.0	84.9	72.6	72.6	397.5	79.5
Pass-through expenditure	44.9	37.1	37.7	36.4	37.1	193.2	341.5
Depreciation	40.1	40.4	42.8	46.1	48.4	217.8	395.5
Return	8.3	9.2	10.3	10.8	11.1	49.7	91.1
Base revenue	168.8	178.7	175.6	166.0	169.2	858.3	1547.8
Other revenue allowance	151.8	146.1	142.0	140.9	137.9	718.7	1285.7
Calculated revenue (before tax)	320.6	324.8	317.6	306.9	307.1	1577.0	2833.4
Tax allowance	2.5	4.9	2.5	0.7	1.3	12.0	21.5
Tax allowance adjustment	-	-	-	-	-	-	-
Calculated revenue	323.1	329.8	320.1	307.5	308.4	1589.0	2854.9