Northern Gas Networks

RIIO-GD3 Draft Determination Consultation Response

Finance Annex

we are the network

Table of Contents

Executive summary

In our Business Plan submission, we highlighted that changing financial market conditions and risks associated with declining gas demand must be appropriately factored into Ofgem's RIIO-GD3 WACC allowance in order to ensure the investability of the gas distribution networks (GDNs).

Ofgem's Draft Determination (DD) proposals represent a positive shift from its SSMC position, and we welcome Ofgem's recognition of relevant evidence in key areas of its allowed return calibration. However, Ofgem's proposals do not go far enough in reflecting prevailing market conditions and sector-specific risks. In particular, a balanced range of cross-checks indicates that Ofgem's proposed return on equity creates investability risks. Only the upper quartile of Ofgem's own Cost of Equity (CoE) range, coupled with a higher Cost of Debt allowance, would constitute an investable package.

Ofgem must revisit the financial parameters at Final Determinations to ensure that its financial package for RIIO-GD3 allows the gas distribution (GD) sector to remain financially resilient and to be in a position to deliver long-term value to customers.

Further technical detail and supporting evidence are provided in our responses to Ofgem's specific consultation questions in the rest of this document. We provide below a summary of key areas where Ofgem's approach needs to be revisited.

Cost of Debt Calibration

While we welcome Ofgem's recognition of the higher debt costs in the gas sector, we consider that Ofgem's methodology for estimating efficient debt costs has to factor in appropriate assumptions to correctly estimate the calibration adjustment. NERA's independent analysis suggests that Ofgem's proposed 60 bps is insufficient and should be set in the range between 79 – 93 bps (excluding sensitivities) for gas companies. This is in part driven by using appropriate assumptions for:

- The proposed Gas Network Premium (GNP), which should be increased from 25 bps to 45 bps to correctly reflect higher gas debt sector costs.
- Ofgem's Additional Cost of Borrowing (ACB), which should be increased from 25 bps to 50 bps to appropriately reflect gas-specific transaction costs, liquidity needs, CPIH basis risk and an infrequent issuer allowance.

We support Ofgem's continued use of the Bank of England's 2% CPI target for deflating ILD returns. Ofgem has said it may consider adopting the OBR's recent 2.4% CPIH forecast, which we would disagree with due to the heavily assumption-driven modelling underpinning this new forecast, which lacks a track record. Adopting this 2.4% assumption is likely to exacerbate debt underfunding and undermine financial resilience.

Return on Equity

Risk-Free Rate: We maintain that Ofgem is wrong not to include a convenience yield in the risk-free rate (RfR), which independent analysis by Oxera estimates at 24bps.

Total Market Return (TMR): On TMR, Ofgem says it is taking a through-the-cycle fixed TMR approach. But Ofgem has applied this in an inconsistent and unbalanced way over time - Ofgem has lowered TMR during periods of low interest rates, but uses the long-term average during periods of high interest rates (as now). This is likely to undermine investor confidence and undermine companies' ability to attract and retain investment during periods of high interest rates. Current market evidence points to a much higher TMR point estimate than Ofgem's proposal of 6.9%. Overall, Oxera's TMR range of 7.0%–7.5% represents a balanced and consistent application of both short- and long-run evidence.

Beta: We welcome Ofgem's inclusion of European gas comparators within its beta estimation. However, Ofgem's proposed midpoint estimate of 0.375 selected from an asset beta range of 0.30–0.45 does not go far enough in reflecting the stranding risk faced by GDNs. We recommend a minimum asset beta of 0.40, based on evidence presented by Oxera and Kairos Economics on European gas comparators, further corroborated by relevant information from US comparators.

Cost of Equity: Given the points above, and the evidence from a broad and balanced range of cross-checks, an appropriate estimate of the GDN CoE for RIIO-GD3 is at least c. 6.5%. This is a conservative estimate in line with the figure proposed in NGN's Business Plan (updated for the latest estimate of RfR).

Financeability and Financial Resilience

We support Ofgem's credit rating target of Baa1/BBB+ but highlight that credit rating agencies have recently tightened thresholds for gas networks. These changes need to be reflected in Ofgem's financeability assessment.

We do, however, have concerns over Ofgem's proposed additional financial resilience measures, particularly the requirement for multi-year resource availability certification by the Board. This requirement will introduce additional costs, as it may require earlier pre-financing. Ofgem must also provide clear guidance on how companies can ensure compliance.

Regulatory Depreciation

We agree with Ofgem's proposal to accelerate depreciation for new assets to mitigate stranding risk. However, we continue to stress that any adjustment to regulatory depreciation can only ever partially mitigate stranding risk. Stranding risk cannot be entirely removed because scenario uncertainty will remain, and the pace of technological change, policy change and customer behaviour change is all highly uncertain. It is therefore necessary to not only mitigate but also compensate for the risks borne by debt and equity investors, unless the government underwrites GDNs' Regulatory Asset Value (RAV).

Overall risk balance of the price control

We do not agree with Ofgem's assumption that there is risk symmetry within the aggregate balance of the whole price control. In our view, the balance of risk is skewed to the downside for a notional GDN. Independent analysis by Frontier Economics, using Monte Carlo simulation, finds that the skew of plausible outcomes of the price control is clearly to the downside. Ofgem should revisit its calibration of the price control to make it more balanced and consider the impact of this built-in downside on the investability of the finance package.

Allowed return on debt questions

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

We do not agree with a number of elements of Ofgem's approach to estimating efficient debt costs for the gas distribution sector. We discuss each of these in the sections below. We note that Ofgem has not provided us with its underlying calculations for the index calibration, and therefore, we cannot comment on the details of Ofgem's calibration approach. We request that Ofgem provide this to networks at its earliest convenience.

Benchmark index

As set out in our Business Plan, we agree with Ofgem's proposal to continue indexing the Cost of Debt (CoD). We address the proposed switch to the iBoxx A/BBB index in response to FQ2.

Exclusion of synthetic debt accretion refinancing from the debt calibration

Ofgem has excluded derivatives (other than cross-currency swaps) from its calibration analysis. The exclusion of inflation swaps in particular means that Ofgem has not properly factored in synthetic index-linked debt (ILD). For example, NGN has c.£186m of accretion refinancing that is due to take place in 2030/31, which hasn't been fully included in the new debt assumptions by Ofgem. This is because if Ofgem factors in 30% (share of ILD) of the 60% (notional gearing) of the CPIH RAV indexation over RIIO-GD3 as a new debt assumption, this would only cover five years' worth of ILD accretion taking place over RIIO-GD3. However, in our case, forecast refinancing of the above-mentioned inflation accretion will have been accumulated over ten years, five of which were in RIIO-GD2 when inflation rates were higher than forecast in RIIO-GD3. This means that due to a timing and inflation rate mismatch, the assumed quantum of new debt in RIIO-GD3 is likely to be underestimated.

Notwithstanding the fact that Ofgem continues to disregard the impact of most derivatives on the sector average cost of debt, we consider that refinancing of inflation swaps should be appropriately factored into the calibration in order to capture the notional efficient debt costs of the sector. This is because there is no difference, in an economic sense, between the inflation accretion of the "pure" ILD bond and a synthetically-derived proxy, both of which result in the same quantum of inflation accretion.

We further note that Ofgem has included synthetic ILD when estimating the proportion of ILD as a share of total debt[1], for the purpose of estimating the proportion of a capital structure linked to inflation, which we agree with. We request that Ofgem do the same in terms of more accurately modelling the quantum of new debt in its gas companies' cohort Cost of Debt calibration, which does not need to extend to the assessment of efficiency of the derivatives.

[1] Ofgem (July 2025), RIIO-3 Draft Determinations - Finance Annex, paragraph 2.34.

Gas Network Premium

We agree with Ofgem's decision to split the gas (GDNs and NGT) and Electricity Transmission (ET) cohorts for the purpose of calibration, given the structural differences in debt costs that are emerging between gas networks and ET due to the transition to Net Zero. These structural differences have been recognised by Credit Rating Agencies (CRAs), who are now tightening credit ratio thresholds, as we discuss further in FQ13 and FQ18.

Ofgem has proposed adding a gas-specific adjustment for new debt of 25bps to the benchmark index. We refer to this as the Gas Network Premium (GNP). Ofgem estimates the 25bps based on the yield to maturity (YtM) of 14 bonds relative to the average A/BBB iBoxx. As evidenced by NERA[1], Ofgem's approach underestimates the GNP as it does not control for differences in tenor between its gas network bond sample (with tenor of c.12 years) and the A/BBB iBoxx (with a tenor of around 19 years).

NERA's analysis of the GNP, which looks at relative spreads at issuance, estimates a GNP of 45 bps (with an absolute minimum estimated at c.32 bps using Ofgem's approach, which NERA disputes). This is based on:

- First, NERA updates Ofgem's methodology, consistently using pricing date data (rather than Ofgem's approach, which inconsistently uses issue date for some bonds and pricing date for others). NERA finds a premium between 31-32 bps when using a sample consistent with Ofgem's, or 32-35 bps when excluding two short tenor bonds which are not reflective of GNP over RIIO-3.
- NERA explains that Ofgem's approach at RIIO-GD3 DD is wrong as it does not control for differences in tenor between gas bonds and A/BBB iBoxx. Therefore, its GNP estimate of 25 bps (and NERA's corrected value of 32-35 bps) is understated because of the shorter tenor of the gas network bond sample of c.12 years relative to the tenor of the A/BBB iBoxx of c.19 years. There is a higher additional borrowing cost associated with a shorter tenor debt caused by interest rate risks, refinancing costs, and so on, which is not factored into Ofgem's estimation of the ACB. Therefore, Ofgem must take into account differences in the tenor of the sample of bonds and the iBoxx A/BBB, fully recognise the higher Additional Cost of Borrowing (ACB) associated with shorter tenors, and make appropriate adjustments to its CoD calibration. We discuss ACB in more detail in FQ4.
- Drawing on Ofgem's approach at RIIO-2, NERA controls for tenor by calculating relative spreads, i.e. gas network debt spread minus iBoxx index spread. NERA finds an average relative spread at issue of 44-46 bps (or 45 bps on average) for gas network bonds issued in the period Jan 2023 – May 2025.
- NERA also finds that gas network bonds are issued at a premium of 33 bps relative to electricity bonds, based on the relative spreads of two pairs of gas and electricity bonds

[1] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks, Section 2.

with similar tenor, credit rating and issued in close proximity. Adding NERA's estimated New Issuance Premium (NIP) of 15 bps[1] to this premium results in a GNP of c. 50 bps.

Approach to forecasting iBoxx

We understand that Ofgem's proposed calibration approach uses the latest available one-month average of iBoxx data as the forecast iBoxx index for RIIO-GD3, rather than using nominal Gilt forward curves as it did at RIIO-GD2.

We note that forward curve interest rate forecasts give a materially higher estimate of iBoxx A/BBB rates over RIIO-GD3, compared with Ofgem's use of the one-month March 2025 iBoxx average of c. 6.1% to calibrate the 60 bps adjustment for the next 5 years. NERA reports that over RIIO-GD3, market forward rates are expected to be c. 1% higher than Ofgem's flat rate assumption[2].

If the forward rate forecast had been used to estimate the DD calibration adjustment, it would have been higher than 60 bps, and this would have gone some way to cover the risk of the actual rates being higher than the calibration assumption. We understand that Ofgem will recalculate the cost of new debt at Final Determinations using more up-to-date iBoxx spot rates as of September 2025, but this does little to mitigate that risk.

Ofgem has explained (through DDQ responses) that it considers there is a risk that forward rates would capture the term premium. While no forecast is perfect, and the predictive power of forward rates may be imprecise, we consider that a one-month iBoxx average exposes the calibration result to a material risk of underestimating the cost of new debt in the RIIO-GD3 period.

Therefore, there does not appear to be any compelling reason to deviate from the established RIIO-GD2 regulatory practice.

We also note that the calibration approach gives smaller headroom for gas networks compared to the electricity transmission (ET) sector, as shown in Ofgem's stress test results, replicated in Figure 1. This exacerbates the risk of miscalibration described above, and if Ofgem decides not to change its approach to forecasting interest rates, it should at least increase the headroom within the calibration for the gas sector.

[1] NERA (22 February 2024), Additional Cost of Borrowing for the RIIO-3 Price Control, page 19.
[2] NERA (22 February 2024), GDNs & NGT Cost of Debt at RIIO-3, page 4.

Figure 1. Difference between expected industry debt costs and expected allowed debt costs, RIIO-3 average, excluding derivatives

Sector	Index calibration	Baseline	Higher Totex	Lower Totex	Rates +1%	Rates - 1%
GD&GT	14 Years TA + 60bps	0.06%	0.05%	0.07%	0.00%	0.11%
ET	14 Year RAV Weighted + 45bps	0.39%	0.39%	0.39%	0.30%	0.48%
ET&ED	14 Year RAV Weighted + 45bps	0.14%	0.14%	0.14%	0.00%	0.27%
ET&ED	14 Years TA + 45bps	-0.54%	-0.55%	-0.53%	-0.86%	-0.21%

Source: RIIO-3 DD Finance Annex, Table 13

Insufficient allowance for the Additional Cost of Borrowing

Ofgem has proposed an adjustment of 25bps for gas networks for the Additional Cost of Borrowing (ACB). We consider that this is insufficient and that the ACB allowance should be 50 bps, in line with NERA's[1] findings. We discuss this further in our response to FQ4.

Impact of insufficient totex allowances

Finally, we observe that highly material cost disallowances relative to Business Plans have been imposed on the sector in the DD, and that GDNs have identified a large number of issues and errors through Ofgem's error-correction process. If Ofgem's Final Determinations (FD) underfunds the Totex requirements for the sector, relative to the necessary and efficient spend that will actually be needed to maintain network safety and reliability, then there would also be a resulting under-estimation of the new debt requirements in RIIO-GD3. This is yet another risk factor that Ofgem should quantify and take into account in its FD when setting headroom under downside scenarios, for its calibration methodology to provide a sufficient Cost of Debt allowance.

Recalculated Calibration adjustment

If the issues outlined above are rectified, NERA's analysis[2] demonstrates that the required calibration adjustment for gas networks should be increased to at least 79 bps (based on an appropriate GNP of 45 bps and ACB of 50 bps, including 6 bps of infrequent issuer premium), compared to Ofgem's 60bps. NERA also finds that if GDNs were assessed separately from NGT, a simple (rather than weighted) average was used, the required calibration adjustment would need to be as high as 93 bps. Downside scenarios tested by NERA push this up even further. Ofgem's calibration adjustment is therefore clearly underestimated, and needs to be

[1] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks, page 6.
[2] NERA (22 August 2025), GDNs & NGT Cost of Debt at RIIO-3. A Report for Gas Networks, page 7.

set in the range between 79 – 93 bps (excluding sensitivities) to compensate the gas sector for the efficient cost of debt forecast in RIIO-GD3.

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+?

We understand Ofgem's rationale for the proposed change from the iBoxx Utilities 10+ to an average of the iBoxx GBP A and iBoxx BBB non-financial 10+ corporate indices as the benchmark index for the cost of debt methodology. While we don't disagree with this change per se, we offer a number of observations which highlight risks that this change may entail.

Ofgem argues that the iBoxx Utilities 10+ has been impacted by sectoral and issuer-specific events in the water sector that are not relevant for the gas and electricity sectors. Instead, Ofgem argues that the use of the iBoxx A and BBB nonfinancial 10+ corporate indices mitigates the risk that the benchmark index is misaligned from energy network company costs, as the water sector represents a smaller proportion of the overall composition.

Despite the greater weight given to water companies in the iBoxx Utilities 10+ index, we consider that this remains the most representative index for the gas and electricity sectors. Although the index is currently impacted by events in the water sector, the more general A and BBB non-financial indices are driven by sectors far more removed from the energy network sectors, and with different risk profiles. Ofgem itself recognised this at RIIO-2 when it adopted this index: *"Although a number of stakeholders expressed concern that the iBoxx GBP 10yr+ Utilities index average rating may diverge from the notional company assumed rating, we consider this risk to be lower (to both networks and consumers) than the risk of the A/BBB combined index diverging from the average borrowing costs of networks."*[1]

We also consider that any elevation or volatility in the iBoxx Utilities 10+ due to events in the water sector is likely to be a transitory phenomenon that will stabilise in the longer term. In fact at the RIIO-2 price review, Ofgem noted that the Utilities 10+ index was more stable than the A and BBB indices: *"We compared this index [Utilities 10+] to the combined BBB and A 10yr+ indices and found that although it exhibited similar movements in both yield and spread terms to the combined A/BBB indices, it exhibited lower yields and spreads in times of financial distress. This is not surprising as we would expect the market to view utilities (which include regulated monopolies providing essential services) to be better insulated from macro-economic shocks than the broader corporate market."*[2]

Debt indices, by their nature, will regularly be impacted by events taking place in other sectors. We do not consider that it is necessary or appropriate to change the benchmark index any time such events occur that are not directly relevant to energy network sectors. Making changes in direct response to potentially temporary "events of the moment" risks undermining the clarity and stability of the regulatory framework. Regulatory consistency and

[1] Ofgem (2021), RIIO-2 Final Determinations Finance Annex, paragraph 2.16.
[2] Ofgem (2020), RIIO-2 Draft Determinations Finance Annex, paragraph 2.12.

predictability are essential to maintaining investor trust and ensuring the sector can attract efficient capital to support vital infrastructure.

Finally, if such events in the regulated water sector prove to be enduring, then it may well represent the objective benchmark for raising finance in the UK utility sector.

We note that Ofgem has switched from iBoxx Utilities back to A/BBB as per RIIO-1, thus undoing the change implemented to RIIO-2. Although technically we do not have objections to either of the underlying chosen indices, we stress that Ofgem risks being seen as cherry-picking if it changes its benchmark each time the benchmark appears to be generous.

We also note that the A and BBB indices are not matched to the target credit rating for GDNs. Ofgem has decided at DD to set the target credit rating to Baa1/BBB+[1], which is half a notch lower than the average credit rating of the A and BBB indices (which falls between A- and BBB+). Therefore, the A and BBB indices are likely to systematically underestimate the debt costs of the energy networks.

Finally, since Ofgem has introduced the so-called "calibration adjustment" to better align the trailing average of the chosen iBoxx index to the gas cohort's efficient cost of debt, as long as the quantum of this adjustment is estimated using the same underlying index, the overall impact on the Cost of Debt allowance is likely to be similar, regardless of the index selection.

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

Ofgem has proposed an ILD notional capital structure assumption for gas of 30%. We consider this assumption to be appropriate as it is broadly aligned with the sector average.

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

We do not agree with the proposed approach and consider that the additional cost of borrowing (ACB) proposed by Ofgem for the gas networks is not sufficient. Ofgem has proposed 25bps for additional borrowing costs based on 15 bps for liquidity costs, 7 bps for transaction costs, and 3 bps for CPIH basis risk mitigation costs.

Our view is that the additional cost of borrowing for the gas distribution sector should be 50 bps, including the infrequent issuer premium, in line with NERA's Gas Network Premium and Additional Cost of Borrowing report[2] - meaning that Ofgem's ACB allowance should be increased by c. 25 bps.

Table 1 summarises the updated findings of NERA's independent assessment of the additional cost of borrowing at RIIO-3, relative to Ofgem's position. Below, we address each component of the ACB in turn. We discuss the infrequent issuer premium in FQ6.

[1] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 5.14.

[2] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks, page 6.

Table 1. NERA assessment of the additional cost of borrowing for RIIO-3, relative to Ofgem

<table>
<tr><th>Component</th><th>Ofgem RIIO-GD2/T2 (bps)</th><th>Ofgem RIIO-GD/GT3 DD (bps)</th><th>NERA RIIO-GD/GT3 (bps)</th></tr>
<tr><td>Transaction costs</td><td>6</td><td>7</td><td>8</td></tr>
<tr><td>Liquidity/RCF costs</td><td>4</td><td rowspan="2">15</td><td>5</td></tr>
<tr><td>Cost of Carry</td><td>10</td><td>26</td></tr>
<tr><td>CPI(H) basis risk</td><td>5</td><td>3</td><td>5</td></tr>
<tr><td>ACB</td><td>25</td><td>25</td><td>44</td></tr>
<tr><td>Infrequent Issuer Premium</td><td>6</td><td>0</td><td>6</td></tr>
<tr><td>Total ACB</td><td>31</td><td>25</td><td>50</td></tr>
</table>

Source: NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks.

Transaction costs

Ofgem has proposed a transaction cost allowance of 7 bps for gas networks. Ofgem's approach is consistent with its approach at RIIO-2, with the only change being the sampling approach: Ofgem has recognised that gas network debt issuances have shortened over time, and therefore it estimates transaction costs separately for the gas and electricity sectors.

In its March 2024 report[1], NERA argued that the gas sector should receive a higher transaction cost allowance on the basis that a shorter observed tenor of gas debts since 2020 will lead to higher per annum transaction costs, as upfront costs are annualised over a shorter tenor. However, in the DD, Ofgem concluded that shorter-term bonds often present lower arrangement and underwriting fees.

As explained in NERA's Gas Network Premium and Additional Cost of Borrowing report[2], it is incorrect to analyse the relationship between bond tenor and the arrangement & underwriting fees in absolute terms. Instead, transaction costs must be assessed on an annuitised basis and expressed as a percentage of the debt issuance amount. A correct analysis shows that there is, in fact, a negative correlation between bond tenor and arrangement & underwriting fees.

[1] NERA (4 March 2024), Impact of GDNs' Reduced Debt Tenor on Additional Cost of Borrowing at RIIO-3.

[2] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks, page 16.

NERA's report estimates transaction costs for gas network bonds issued since January 2023 to be 8 bps. These bonds present a shorter tenor and higher transaction costs compared to those issued before January 2023. This is consistent with a negative correlation between bond tenor and transaction costs.

Liquidity / RCF

Ofgem has proposed a liquidity allowance of 2 bps (within its overall liquidity and cost of carry allowance of 15 bps). In our view, the liquidity allowance is too low as it does not allow cost of drawdown and understates the size of RCF facilities. Independent analysis by NERA[1] estimates a liquidity allowance of 5 bps based on:

- **The inclusion of the utilisation fee and margin**. NERA's analysis shows that utilisation fees and associated margin should be included as data on intra-year cash balance shows that, on average, companies draw down 3.1% of their RCF facilities to fund working capital requirements and operational needs.
- **A larger RCF.** NERA estimated the average RCF facilities using the same data as referenced by Ofgem in the DD (i.e. average of all energy network companies' 2-year actual historic RCF and debt data). According to NERA's analysis, RCF facilities represent 14.6% of companies' debt, which is higher than Ofgem's 10% estimate.
- NERA also considers additional **costs of maintaining RCF**, such as upfront arrangement fees and legal fees, which are excluded by Ofgem. However, these additional costs are small, only amounting to 1bp per annum.

Cost of Carry

Ofgem has proposed a cost of carry allowance of 13 bps, based on the five-year average difference between iBoxx GBP A and BBB non-financial 10+ indices and the 3-month cash deposit rate, plus Ofgem's GNP estimate of 25bps. Ofgem assumes the proportion of cash and cash equivalents on networks' balance sheets represents 7.7% of average debt, based on 2 years of historical data.

In line with NERA's findings[2], it is our view that Ofgem understates the cost of carry allowance as it is based on backwards-looking data that does not properly capture the costs that GDNs are expected to face in RIIO-GD3. NERA estimates a cost of carry of c. 26 bps, based on:

- Higher **iBoxx-cash deposit spreads**. NERA's analysis shows that historical data is not reliable, as it includes the 2023-24 period, which is a historically abnormal period of low spreads, as shown in Figure 2.

---

[1] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks, page 23.

[2] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks, page 21.

Figure 2 has been redacted due to data licensing restrictions and copyright limitations associated with iBoxx data.

- An **updated assumption on cash-to-debt ratio** of 10%, in line with an expected change in investors' preferences towards shorter tenor debt because of increasing risks at RIIO-GD3. NERA assumes that gas companies will need to issue shorter tenor debt and amortise the cost of carry over a 10-year period (leading to a 10% cash/debt ratio), instead of a 13-year bond tenor (leading to Ofgem´s 7.7% cash/debt ratio assumption).

These findings are corroborated by our internal policy and experience. NGN's Treasury Policy requires that the maturities of debt instruments are to be managed such that at any one time all have a time to maturity of more than six months, subject to additional provisions around compliance with auditors' going concern requirements and Ofgem's availability of resources certification. In practice, depending on timing, this can mean that maturing debt is refinanced more than 12 months ahead of maturity. For example, NGN intends to raise new debt in June 2026 to provide funds to repay a £250m bond maturing in June 2027, which constitutes c. 12% of NGN's current debt book.

CPI(H) basis risk

Ofgem has proposed a CPIH basis risk mitigation of 3 bps for the gas networks based solely on RPI/CPI swap costs assumptions.

In estimating RPI-CPI basis risk, Ofgem assumes companies will issue RPI ILD and then issue RPI-CPI swap at a cost of 15 bps. We agree with NERA's view that Ofgem is wrong to exclude nominal-CPI inflation swaps in its estimation of CPI-linked issuance costs. NERA explains that most of the gas networks (and this applies to NGN) do, in fact, rely on issuing synthetic CPI-linkers, as evidenced by companies' derivatives data. While it is possible for a company to issue RPI ILD and then issue RPI-CPI swap, there are practical limitations to issuing RPI ILD.

NERA estimates the cost associated with managing CPI(H) basis risk to be 15 bps to 50 bps, based on the cost of RPI-CPI swaps (15 bps) and the cost of structuring a nominal-CPI inflation swap (30-50 bps).

Therefore, we consider that the cost for managing CPI(H) basis risk needs to be allowed at c. 5 bps (an average between the bottom end of the range of c. 3 bps based on managing basis risk based on RPI-CPI swaps and the top end of the range of c. 6 bps based on the prevailing practice of swapping nominal debt to CPI).

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

We agree with Ofgem's approach to deflating the allowed return (based on nominal bond yields) for the index-linked portion of debt, using the Bank of England's CPI inflation target of 2%. This is a natural anchor-point for investors' long-term inflation expectations, given the BoE's role is actively to steer the economy (via monetary policy) towards that inflation level. There is no reason to believe the BoE might systematically miss the target in the long term.

However, Ofgem has indicated in the DD that it "will review" whether to instead rely on a 2024 OBR report[1], which suggested a long-run wedge between CPIH and CPI of 0.4%. Ofgem indicates it might therefore consider using a CPIH long-run assumption of 2.4%.[2] We understand Ofgem's DD proposal is, however, to use 2% and no review of the OBR number has yet been undertaken by Ofgem.

Once Ofgem has completed its review, and should Ofgem be minded to change its DD proposal, this would represent a significant and material change of approach. The sector would therefore need to be given sufficient opportunity to be thoroughly consulted via a dedicated consultation process, with the associated impact assessment, ahead of the FD.

To aid Ofgem's own review, we offer some initial observations below.

We do not agree that 2.4% is an appropriate inflation estimate to use for the purposes of deflating the allowed return for ILD. In summary, the reasons for this include:

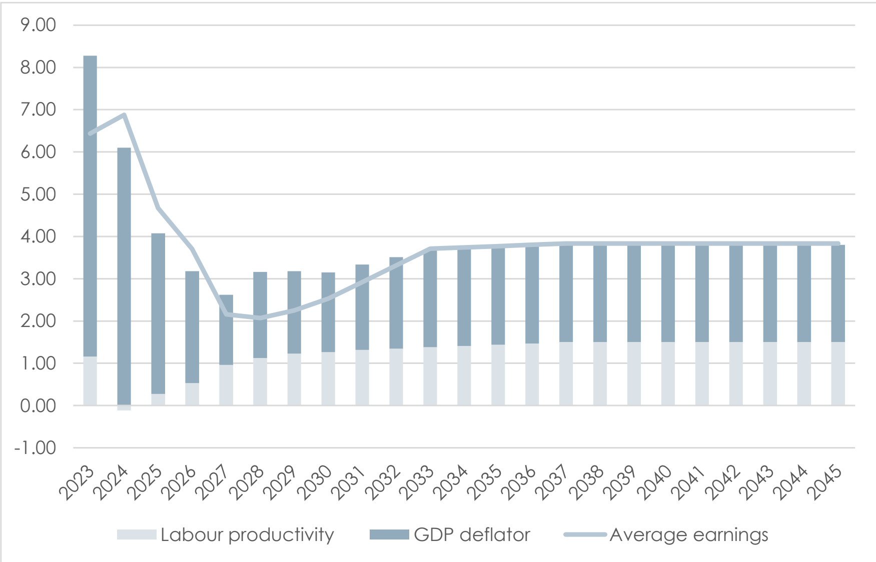
- The provision of this forecast is new, and there is a lack of track record on its forecasting performance.
- The long-term CPIH assumption appears to differ from 2% primarily because of an assumption on average earnings growth reaching 3.8% per annum from 2036/37 onwards. It is not obvious that there is any meaningful forecast between OBR's medium-term end-point of 2029-30 and its long-term assumption. The figure of 3.8% has not been changed in any of the OBR's updates of the Long Term Economic Determinants in the last 5 years, suggesting it is not based on any recent long-term modelling which is updated to reflect changes in the economy.

[1] OBR (2024), Economic and Fiscal Outlook – October 2024.
[2] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 2.49.

We expand on some of the key issues with the OBR 2.4% assumption in more detail below.

Given the OBR's reliance on average earnings to forecast owner occupiers' housing costs (OOH), it is useful to inspect the components of the OBR's forecast of average earnings (nominal). The OBR's long-term assumption for average earnings growth is obtained as the sum of labour productivity and the GDP deflator. Figure 3 shows the OBR's assumptions on how these underlying variables develop in the medium and long term.

Figure 3. Evolution of labour productivity, GDP deflator and average earnings, 2027-2045



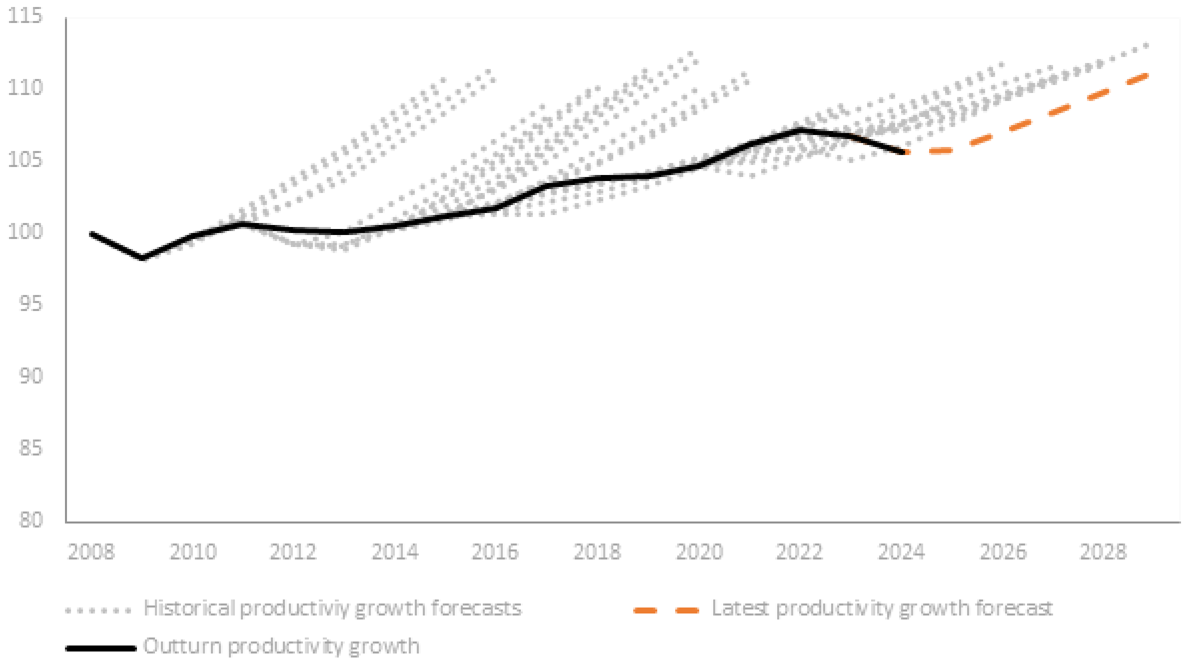
Source: OBR, EFO March 2025

From Figure 3, we can see that a 3.8% earnings growth assumption applies from year 2036. There also seems to be a change in the profile of the assumptions - before 2033, average earnings are not equal to the sum of labour productivity and GDP deflator; whereas after 2033, the OBR assumes this to be the case. This suggests there may be a structural difference in the OBR's approach to its flagship 'Year 5' forecast and its long-term forecasts.

We can also observe that labour productivity makes up a significant proportion of the earnings growth assumption. In the medium term, labour productivity is forecast at 0.27% in 2024-25, increasing up to 1.27% in 2029-30. Long-term labour productivity is assumed at 1.5%. The basis of this assumption is unclear, particularly considering that labour productivity was negative in 2024 (-0.12%). The OBR has not published any information on the underlying methodology for these long-term assumptions, which seem to be reached by applying a glidepath to the last year of the medium-term forecast (as can be seen from Figure 3).

We also note that the OBR's productivity estimates have tended to be optimistic in the past, i.e. overestimated relative to the realised value.[1] Figure 4 also illustrates the OBR's forecasts of labour productivity (grey shaded lines) against outturn productivity (solid line).

Figure 4. Productivity growth forecasts and outturn productivity growth (2008=100)



Source: Oxera (August 2025) RIIO-GD&GT3 cost of equity and debt premium cross check. Prepared for Future Energy Networks. Figure 2.4

Based on our understanding of the OBR's assumptions for CPIH in the longer term, an overestimation of productivity would imply that 2.4% is an overestimation of long-term CPIH.

More generally, the OBR's long-term CPIH assumptions have only been published since early 2023. This is therefore still relatively new and untested, and as such must be subject to uncertainty.

In summary, therefore, using 2.4% would introduce a significant risk of overstating the inflation assumption, resulting in insufficient cost of debt allowance on 30% of the debt book. This would cause an undue risk of underfunding the cost of debt. We consider the Bank of England's long-term CPI assumption of 2.0% is still the best long-term inflation assumption to be used in RIIO-GD3.

---

[1] See for example: https://www.bbc.co.uk/news/business-42012388, https://www.ft.com/content/768843e8-a839-11e7-93c5-648314d2c72c, https://www.ft.com/content/78411bc5-7d90-41c0-91d5-c8f449f52c00.

FQ6. Do you agree with the removal of the infrequent issuer allowance?

We do not agree with Ofgem's removal of the infrequent issuer allowance.

Ofgem argues in the DD that additional costs arising from infrequent issuance would already be captured in the data used to calibrate the main debt allowance, because the use of derivatives to manage infrequent issuance is limited, and because the data used to calculate the gas 25bps benchmark adjustment for new debt is predominantly drawn from infrequent issuers.[1]

To Ofgem's first point, NGN has to use derivatives for interest rate hedging (against the regulatory cost of debt allowance) because, as an infrequent issuer, we cannot align our costs with the cost of debt allowance through pure debt issuance. Using derivatives to hedge this risk means that we incur additional costs relative to frequent issuers (by way of credit and execution spreads levied by banks), and our view is that these costs should be remunerated. While other infrequent issuers may decide not to carry out interest rate hedging, those companies are making a decision to bear that risk, and as a result, they may also be underfunded through the cost of debt allowance.

To Ofgem's second point, NERA[2] finds that 43% of the sample debt instruments used to estimate GNP are not issued by infrequent issuers and hence the GNP does not fully compensate for the infrequent issuer premium. Moreover, we note that although the yields of debt used to calculate the benchmark (calibration) adjustment will capture any illiquidity premium in cases where they are issued by infrequent issuers, they will not capture the interest rate risk hedging costs described above. Therefore, a separate allowance is needed to cover such costs – otherwise, a notional small or infrequent issuer would be disadvantaged compared with larger counterparts that can issue debt more frequently to manage the interest rate risk without the need to utilise derivatives.

NERA estimates the upper bound for the infrequent issuer premium based on evidence from constant maturity swaps (CMS), in line with Ofgem's RIIO-2 approach. CMS only cover the interest rate risk, but the credit spread risk is not hedged. NERA estimates that CMS costs range from 18 bps to 41 bps, which supports an estimate for the infrequent issuer premium of 9bps (midpoint of the range, multiplied by 31% new debt assumption).

NERA also analysed primary market evidence based on relative spread at issue of a wide sample of energy network debt. This evidence shows a 21-24 bps differential in relative spread at issue between issues below £250m relative to issues above £250m. Around half of the sample of Ofgem's bonds are sub-benchmark £250m. Therefore, half of the estimated small issue premium should be reflected in the GNP. Consequently, the 21-24 bps of small

[1] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 2.95.

[2] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks, page 30.

issue premium translates to an infrequent issuer premium of 3.5bps (half of 22.6 bps * 31% new debt assumption), which forms the lower bound of NERA's range.[1]

Therefore, our view remains that Ofgem should provide an infrequent issuer premium. Based on the latest evidence from NERA's work, this premium should be on average c. 6 bps, which is equivalent to the infrequent issuer allowance provided by Ofgem in RIIO-GD2.

Finally, we note that infrequent issuers tend to incur additional costs of carry, as they are likely to need to raise more debt than immediately needed. Not all of the new debt will be reflected in the RAV immediately, meaning that the full debt cost is not remunerated through the RAV for a period of time. This additional cost has not been captured by NERA in its carry cost estimate, which means that the 6 bps estimate for the infrequent issuer allowance is conservative.

Allowed return on equity questions

FQ7. Do you agree with our methodology for calculating the RFR?

We disagree with Ofgem's rejection of the convenience yield in its methodology for setting the RfR, although we support the indexation of the RFR more generally.

Ofgem has retained its SSMD approach to setting the risk-free rate (RfR) for each year of the price control based on the one-month (October) average of 20-year index-linked gilt (ILG) yields. It has continued to reject the use of AAA non-gilt bonds (or inclusion of an uplift) to account for the convenience yield in ILGs.

There is strong evidence of a convenience yield, both theoretical and empirical. As we set out in our Business Plan Finance Annex, investors value ILGs due to their liquidity characteristics and their role in hedging strategies. This leads to excess demand for ILGs, meaning that the Government can borrow at rates lower than even a theoretically risk-free corporate borrower.

Ofgem argues that there is no compelling evidence of the convenience yield in ILGs at the 20-year investment horizon. Oxera's Cost of Equity report[2] addresses Ofgem's arguments in relation to the academic literature that supports the convenience yield.

Oxera also provides additional empirical evidence that the convenience premium persists over time and is not only present during distressed financial markets. Although the spread between AAA-rated bond indices and gilts increases during periods of financial distress, a spread can be observed during stable periods as well.

Oxera estimates the convenience yield to be 24bps.

---

[1] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks, page 32.

[2] Oxera (22 August 2025), RIIO-GD&GT3 cost of equity and debt premium cross-check. Prepared for Future Energy Networks.

Further to the updated analysis presented above, the yield on ILGs is not directly relevant for the cost of capital calculations for regulated network companies since these are not typically the risk-free benchmark used in the vast majority of financing arrangements. In fact, ILGs represent less than a quarter of all outstanding UK Government debt, according to data from the Debt Management Office.[1] In the corporate bond market, debt is typically priced at a spread over nominal government bonds, and therefore, it is these bonds that are relevant for estimating the RfR. For equity, there is no reason why investors would use the ILG as a benchmark for RfR more than the bond market.

Oxera also references the Brennan (1971)[2] model in support of the convenience premium. Brennan demonstrated that the risk-free rate at which investors can borrow is higher than the risk-free rate at which they can lend. The market equivalent risk-free rate is a weighted average of the risk-free rates of all individual investors and therefore lies between the borrowing and lending rates. The CMA explicitly referenced Brennan's finding at the PR19 redetermination,[3] and stated that "we have applied a highly-simplified but, in our opinion, reasonable assumption that we can gain sufficient insight into the market RFR by assessing the likely RFR of interest applicable to two appropriate market participants: 1) the government and 2) the highest rated (lowest cost) nongovernment borrowers." That is, the CMA used ILGs as a proxy for the risk-free saving rate and AAA-rated corporate bonds as a proxy for the risk-free borrowing rate.

Ofgem has pointed out that the CMA separately concluded at RIIO-2 that Ofgem's use of ILG data alone was 'not wrong'. However, importantly, the CMA was clear that there was evidence supporting the existence of a convenience premium:

"[…] we agree that ILGs are an imperfect proxy for the RFR (a view shared by GEMA). Specifically, we noted that there is evidence to support the notion of a convenience yield in government-issued securities, and we disagreed with the view that the appropriate investor when considering the RFR is a net lender."[4]

Our view is that the CMA's own approach at PR19 represents best practice, noting that it clearly reasoned at PR19 that it is *"unlikely that the yield on ILG is a perfect representation of a theoretical RFR (or the average market participant rate in the Brennan approach)"*.

Table 2 summarises Oxera's estimation of the RfR.

[1] HM Treasury (26 March 2025), Debt Management Report 2025-26.
[2] Brennan (December 1971), Capital Market Equilibrium with Divergent Borrowing and Lending Rates.
[3] CMA (March 2021), Anglian Water Services Limited, Bristol Water plc, Northumbrian Water Limited and Yorkshire Water Services Limited price determinations - Final report, paragraph 9.263.
[4] CMA (2021), Final determination Volume 2A: Joined Grounds: Cost of equity, paragraph 5.68.

Table 2. Oxera's estimates of the RfR

	Formula	Ofgem (RIIO-3 DD)	Oxera estimates
20Y ILG yields, RPI-real[1]	[A]	1.91%	1.91%
Convenience premium	[B]	–	0.24%
Benchmark RFR estimate, RPI real	[C] = [A] + [B]	1.91%	2.15%
RPI–CPIH wedge	[D]	0.10%	0.10%
RFR, CPIH-real	**[G] = (1+[C]) × (1+[D]) - 1**	**2.01%**	**2.25%**

Source: Oxera (22 August 2025), RIIO-GD&GT3 cost of equity and debt premium cross-check. Prepared for Future Energy Networks, Table 2.4.

We understand that Ofgem is likely to update its estimate of the RFR for the Final Determinations based on September 2025 market data. Therefore, the estimate of 2.25% presented above will need to be updated accordingly, preserving the 24 bps adjustment for the convenience premium and the 10 bps adjustment for the RPI/CPIH wedge.

FQ8. Do you agree with our methodology for calculating the inflation wedge?

In our view, Ofgem has taken a reasonable approach to calculating the inflation wedge between RPI and CPIH. Ofgem uses OBR forecasts for RPI and CPI up to the point of convergence of RPI and CPIH (assumed to be February 2030), and a wedge of zero beyond that point. Ofgem's approach gives a wedge of 10 bps.

To calculate the wedge, in the SSMD, Ofgem proposed using CPI as a proxy for CPIH, given that (i) longer-term CPIH forecasts are less readily available and (ii) the fact that, historically, CPI and CPIH rates of inflation have been very close on average. It has continued to do so at DD. However, Ofgem has said that it will consider a potential adjustment to the inflation wedge in light of the OBR's long-term forecast of CPIH at 2.4%[1], which implies a long-run CPI-CPIH wedge of 0.4%. The suggestion is that the use of CPI as a proxy for CPIH may result in the wedge being overestimated.

We consider that there is no requirement for such an adjustment. First, as stated by Ofgem in the SSMD and DD, the inflation wedge will only exist until 2030, when RPI and CPIH will converge. In the longer term, the wedge between RPI and CPIH will be zero, and therefore any CPI-CPIH wedge (if it exists) will become irrelevant.

[1] OBR (2024), Economic and fiscal outlook – October 2024, Box 2.3.

In any case, historical data does not show a persistent or material CPI-CPIH wedge, as shown in Oxera's report[1]. We also refer to our response to FQ5, which identifies our concerns with Ofgem's contemplated use of the OBR's long-term 2.4% figure, in particular.

Finally, we note that even if Ofgem were to consider using a potentially more reliable medium-term CPIH forecast from the OBR, then a 20-year geometric average of the RPI/CPIH wedge over RIIO-GD3, combined with a wedge of zero from 2031/32, would produce a similar result to Ofgem's DD estimate.

In any case, if Ofgem were to consider changing its DD position, we would expect that the sector would be provided with an opportunity to engage further with Ofgem on these concerns ahead of the FD via a dedicated consultation with the associated impact assessment.

FQ9. Do you agree with our methodology change in calculating the ex ante TMR?

While we agree with Ofgem's methodology change for calculating the ex ante TMR, we do not agree with Ofgem's overall approach to setting the TMR, which we consider should be adjusted to reflect prevailing market conditions.

At DD, Ofgem has proposed a TMR range of 6.8% (based on ex ante analysis using the DMS decompositional approach) to 6.9% (based on ex post analysis using the 1-year arithmetic average of historical returns from the DMS dataset). Ofgem ultimately selects a value of 6.9% for the TMR. Oxera's analysis estimates a higher ex-post TMR of 6.95% which, in line with Ofgem's approach, would be rounded up to 7%.[2]

Notwithstanding our view that ex ante estimates of the TMR are flawed (as set out in more detail in our Business Plan), we welcome Ofgem's methodology change from SSMD in calculating the ex ante TMR, as it reflects improved data availability from DMS, meaning that there is no longer a need to make the adjustment from the Cost of Living Index (COLI) to the Consumption Expenditure Deflator (CED). We also consider that Ofgem's decision not to make a serial correlation adjustment reflects our earlier criticism of the lack of compelling evidence to support the need for such an adjustment.

As set out in our Business Plan, our view is that the TMR should be set at 7.0% as a minimum. Prevailing market conditions currently point to a TMR of above 7.0% and closer to c. 7.5%, which is robustly justified in Frontier Economics' Cross Checks report.[3] Oxera's Cost of Equity report[4] also explains that the evidence indicates that investors are likely to expect higher required market returns than the estimate of 7% for the 'through-the-cycle' TMR, and

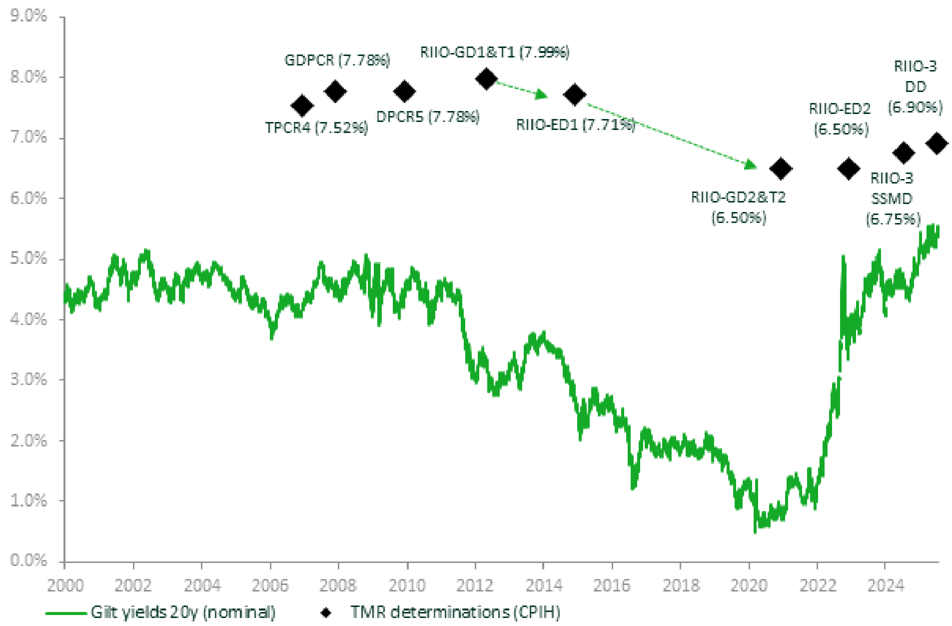
[1] Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks, Figure 2.3.
[2] Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks, page 43.
[3] Frontier Economics (22 August 2025), Updated Cost of Equity Cross-check Evidence. A Report Prepared for Future Energy Networks.
[4] Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks , Page 45.

concludes that a TMR range of 7.0–7.5% would be appropriate for RIIO-3. Below, we explain why we believe prevailing market conditions need to be accounted for.

TMR can be highly variable in the short term. Ofgem has indicated that its intention is to take a stable, 'through the cycle' approach to setting the TMR. For example, at SSMC, it stated, *"We understand that a stable TMR assumption may mean that at certain points in the equity performance cycle, our TMR estimate may appear slightly too high or too low relative to some measures of expectations for near term equity performance. However, when setting our allowed return on equity we are estimating a long-term cost of equity, not trying to predict short-term market performance, and we see value to investors and consumers in the consistency and predictability provided by the stable TMR approach."*[1]

Although Ofgem and other GB regulators claim to take a 'through the cycle' approach, scrutiny of actual TMR decisions clearly demonstrates that Ofgem and other regulators have not kept the TMR at a consistent and stable level, but have historically adjusted the TMR to reflect prevailing market conditions. In particular, as we set out in our Business Plan and as shown in the updated Figure 5 from Oxera, regulatory decisions on real TMR allowance have drifted downwards since the global financial crisis, following the trend in interest rates.

Figure 5. Historical TMR determinations and underlying gilt yields



Source: Oxera (August 2025), RIIO-GD&GT3 cost of equity and debt premium cross check. Prepared for Future Energy Networks, Figure 3.1.

[1] Ofgem (2025), RIIO-3 SSMC Finance Annex, paragraph 3.59

Just as TMR estimates were set well below long-run average returns during the period of low interest rates, our view is that Ofgem's decision on TMR must now reverse that trend and recognise the context of higher interest rates. Figure 5 shows that the increase in gilt yields observed in recent years has coincided with only a marginal increase in the allowed TMR. Oxera notes that between 8 December 2020 and 31 March 2025 gilt yields increased by 4.52% (from -2.58% to 1.93%) on a real basis, while the allowed TMR increased by only 0.4%. In comparison, between 17 December 2012 and 8 December 2020, gilt yields reduced by 2.56% (from -0.02% to -2.58%) on a real basis, while the allowed TMR decreased by 1.49%.

Oxera also finds that DMS now predicts equity returns that are 240bps higher compared with projections made in 2022. According to DMS, this rapid change is the result of the sharp increase in real interest rates and the 'very poor' returns experienced in 2022.[1] This suggests that Ofgem's purported 'through-the-cycle' TMR risks becoming more and more detached from investors' required returns.

Indeed, the purported 'through-the-cycle' approach will by definition be misaligned with market conditions at any given point in time. In periods of low interest rates, it will overstate TMR[2], potentially leading to high asset valuations, which can lead to public scrutiny and questions around regulatory legitimacy. On the other hand, during times of constrained capital markets and high interest rates, this same approach can underestimate the returns required to attract capital, risking underinvestment and a loss of investor confidence.

In practice, though, Ofgem is employing an inconsistent approach over time - setting the TMR at the historical average at times of high interest rates, but lower than the historical average at times of low interest rates (as shown in Figure 5). Furthermore, the way in which Ofgem reached various TMR decisions over time is opaque, unpredictable and based on arcane technical arguments such as backcast CPIH inflation over the 120 years of equity returns, serial correlation in the returns, etc.

It remains entirely unclear to observers how Ofgem's TMR range can go from 6.25%-6.75% at RIIO-2 to 6.8%-6.9% at RIIO-3, when the underlying input data to the calculation (the DMS returns yearbook) reports no material difference in this period. We have always maintained that Ofgem's RIIO-2 long-run TMR was significantly underestimated. But the CMA upheld Ofgem's RIIO-2 TMR decision largely due to the contemporaneous evidence from the capital market at the time (ultra-loose monetary policy, high transaction valuation, etc.), which was interpreted as an indication that the required return in the equity market was not as high as the historical average.

Investors, therefore, are likely to have understood that Ofgem (and other UK regulators) were gauging the wider market conditions when estimating this supposedly fixed long-run average in RIIO-GD2 and thus will continue to do so in RIIO-GD3 in practice, hence producing a different estimate each time on a parameter it claims to be relatively 'fixed'.

[1] Dimson, E., Marsh, P. and Staunton, M. (2025), 'UBS Global Investment Returns Yearbook 2025', page 103.
[2] UKRN (2023), Cost of Capital Guidance, pages 19-20.

Our view is therefore that the TMR should be relatively stable but not fixed 'through the cycle' and it should reflect contemporaneous market data and expectations (without unnecessarily following short-term volatility), in order to be able to attract and retain capital, and demonstrate a balanced approach to setting the TMR. Reflecting market conditions is particularly important at present, where the current need for large-scale infrastructure investment across regulated sectors coincides with a challenging capital market environment.

Frontier Economics formulated such an approach that was submitted to Ofgem in response to its SSMC.[1] This 'TMR Glider' approach estimates a (linear) relationship between the market-implied required TMR (based on a Dividend Growth Model (DGM)) and gilt yields. The Glider provides a view on the required TMR based on current market conditions. It can therefore be used to set a point estimate that reflects prevailing market conditions. Frontier finds that the prevailing market conditions in the past two years strongly suggest a RIIO-3 TMR range of 7.0%-7.5%, and recommends a point estimate towards the top end of that range.

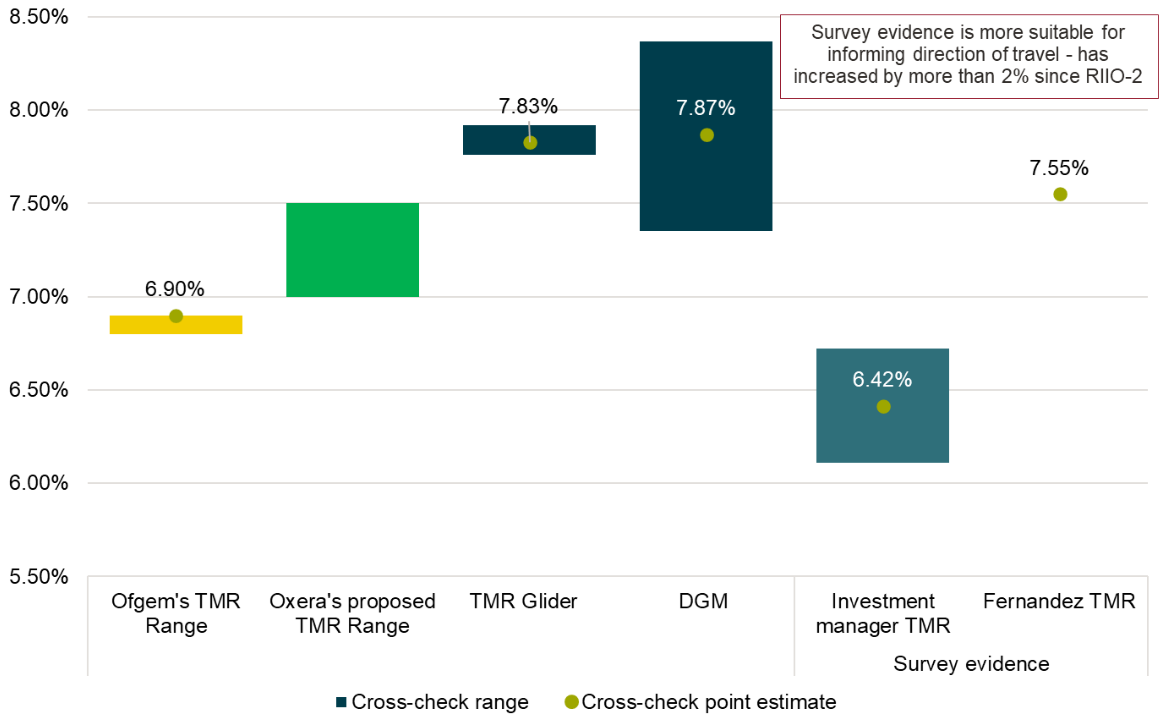
We note that Ofgem has not placed weight on the TMR Glider, based on concerns over the reliability of DGM-based methods. But at the same time, Ofgem continues to rely heavily on MAR cross-checks that are based on the same DGM logic. In doing so, Ofgem has not justified the differing and partial treatment of conceptually similar cross-checks. This is detailed further in Frontier's report on standards of evidence for cross-checks.[2]

Oxera's Cost of Equity report also supports a TMR range of 7% - 7.5%. Oxera estimated a long-run average TMR of 6.95% that should be rounded to 7% in line with Ofgem´s approach. Given the considerations set out above, Oxera argues that it would be reasonable for investors to expect TMR returns as high as 7.5%. Our view is that only a TMR of 7.0% or above is aligned with the long-run evidence and will provide an investable package if combined with other correctly estimated CAPM parameters.

Finally, Frontier Economics also presents a number of TMR cross-checks, summarised in Figure 6. The cross-check evidence suggests that the market required rate is currently significantly above the long-run average.

[1] Frontier Economics (March 2024), The Relationship Between Total Market Return and Gilt Yields.
[2] Frontier Economics (22 August 2025), Cross-check Standards of Evidence. A Report Prepared for the Energy Networks Association and Future Energy Networks.

Figure 6. Summary of TMR cross-checks



Source: Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks, Figure 15.

We note that Ofgem has continued to rely on its TMR survey cross-check ('Investment manager TMR'), collating forecasts from nine financial institutions. Ofgem reports that the average TMR forecast from these financial institutions is 5.9% in CPIH-real or 8.0% in nominal terms.[1]

Frontier Economics[2] sets out a number of issues with this cross-check.

- Ofgem has only looked at the forecasts of nine financial institutions, which can lead to a biased TMR forecast result and not accurately reflect the real market expectations of TMR.
- Ofgem has not specified which nine institutions comprise its sample of forecasts, creating issues of replication and traceability. Ofgem criticised the Fernandez TMR survey evidence put forward by Frontier Economics previously for the same reason of traceability.

Frontier further explains that Ofgem's investment manager TMR forecast cross-check does not appear to have incorporated all the available market evidence. Frontier's updated range is shown in Figure 6 above.

[1] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 3.96.
[2] Frontier Economics (22 August 2025), Updated Cost of Equity Cross-check Evidence. A Report Prepared for Future Energy Networks.

Frontier has previously recommended that Ofgem look at evidence from the annual survey of risk-free rates and market risk premium (MRP) conducted by Fernandez *et al.* The survey asks academics, analysts and managers of companies across many countries about the risk-free rate and MRP used "*to calculate the required return to equity in different countries*".[1] Frontier recommends that the survey evidence should be used to ascertain trends rather than arriving at point estimates, and the Fernandez survey is well-suited for this purpose as it covers a wide sample and is reported on a consistent basis.

Updated evidence from the Fernandez survey points to a significant increase in the TMR between 2020 and 2024 – an increase of c. 3 percentage points from 6.9% in 2020 to 9.7% in 2024 in nominal terms.

Ofgem has proposed not to use this cross-check, as it already utilises a cross-check based on the TMR forecasts from investment managers' firms. It also stated that the Fernandez survey had 82 responses for the UK TMR estimate, and that there is no detail on who the respondents are. We agree with Frontier's response on this point, that the inputs from more than 80 respondents should give a better indication of the market expectations of UK TMR than a selection of nine financial institution forecasts. Frontier also points out that the study takes steps to enhance the robustness of the results, e.g. exclusion of outliers, and filtering out countries and parameters for which fewer than a certain number of responses have been received. Taken together, these features give confidence in the reliability of results.

In conclusion, there is a risk that Ofgem's decision not to adjust the TMR upwards above the long-run historical average could be interpreted by investors as a signal to expect different treatments in scenarios of increasing and decreasing interest rates. This could undermine companies' ability to retain and attract investment at RIIO-3. In the longer term, it could also detrimentally impact investors' confidence as well as regulatory stability and predictability.

FQ10. Do you agree with our methodology for estimating beta?

We welcome that the upper end of Ofgem's beta range has moved materially from SSMD (where Ofgem proposed an asset beta range of 0.30 – 0.40, translating to an equity beta range of 0.64 – 0.89), to DD (asset beta range of 0.30 – 0.45, translating to an equity beta range of 0.64 – 1.01). In our Business Plan Finance Annex, we set out our view that Ofgem's SSMD range disregarded evidence of higher betas for European gas comparators, and that only the very top end of Ofgem's SSMD beta range started to adequately reflect the evidence around levels of risk in the gas sector (including asset stranding risk). We therefore welcome Ofgem's more balanced DD range, which now properly captures evidence from European gas comparators.

[1] Fernandez, Pablo and García de la Garza, Diego and Fernández Acín, Javier (2023), Survey: Market Risk Premium and Risk-Free Rate used for 80 countries in 2023, page 2. The 2024 edition has outputs for 96 countries.

However, as set out in Oxera's Cost of Equity report[1], the beta should reflect how risky the equity investment is expected to be compared to an average market portfolio. Although we acknowledge that considering the historical evolution of European gas comparators is a move in the right direction, it is not clear that all the forward-looking risks (i.e. stranding risk, increased competition for alternative investment opportunities) will be captured in the historical beta estimates.

Moreover, we remain of the view that the bottom end of Ofgem's range is too low. It is, in fact, lower than even the 10-year betas of GB water companies, which clearly do not face the asset stranding risks present in the GD sector. Ofgem argues that GB water companies also face Net Zero risks; however, it has not explained what these risks are, and in our view, any such risks (e.g. around decarbonising the process of treating and transporting water) are far less material than the asset stranding risk impacting GB gas networks.

Notably, the average 10-year asset beta of the water companies, taken together, is 0.34, compared to the average of the EU gas comparators, which is 0.40. Moreover, regulatory decisions for gas sectors in the EU point to even higher estimates. Oxera[2] presents regulatory precedents on asset beta allowances in six European jurisdictions (Italy, Spain, France, the Netherlands, Germany and Portugal), and finds that:

- Unadjusted asset beta allowances for gas transmission range from 0.38 in Portugal and Italy to 0.47 in France, with an average of 0.41 and a midpoint of 0.425.
- For gas distribution, unadjusted asset betas range from 0.39 in the Netherlands to 0.50 in Spain, with an average allowance of 0.43 and a midpoint of 0.445.

Ofgem's proposed asset beta of 0.375 lies below these ranges and well below the averages shown above.

Even though Ofgem has not included US comparators in its assessment and notwithstanding some differences in regulatory regimes, Oxera shows that UK, EU and US betas follow very similar trends over a long period of time. This suggests that US evidence provides valuable information about betas, given the absence of publicly listed pure-play gas networks in Great Britain. US betas for gas companies point to an even higher level of beta, with an average 10-year asset beta of 0.47[3].

Oxera's report also refers to the extensive academic literature[4] that suggests that the CAPM model understates the actual returns earned by companies with low beta and volatility, such

[1] Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks, page 47.
[2] Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks, Section 4.2.
[3] Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks, Section 4.3.
[4] For example, see Black, F., Jensen, M. and Scholes, M. (1972), 'The Capital Asset Pricing Model: Some Empirical Tests'.

as regulated utilities. This provides additional support for selecting a point estimate closer to the upper bound of the asset beta range.

Kairos Economics[1] argues that a positive and material (0.02-0.03 in asset beta terms) differential between gas and electricity betas estimated across multiple jurisdictions suggests that, at the very least, Ofgem should place more weight on the beta estimates of the comparator European gas networks. This would mean setting a CAPM beta estimate for gas networks above the mid-point of an appropriate range based on all comparators.

Overall, we agree with Oxera's proposed gas-specific asset beta range of 0.40 – 0.44. In our view, Ofgem should aim up within its "vanilla" CAPM asset beta range and set the asset beta at 0.40 for gas companies as a minimum, in order to properly capture the asset stranding risk faced by GDNs.

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

We support Ofgem's decision to include European utility comparators to provide more robust beta estimates and to help address the lack of gas sector comparators in the UK.

We consider that the inclusion of European comparators is key, especially in an environment where asset stranding risk is growing as the energy transition progresses, and is not captured in any of the GB beta comparators. The Oxera European beta comparators report[2] submitted alongside our Business Plan, reviewed the regulatory regimes and business mixes of the five European comparators identified by Ofgem, and found that the level of risk faced by these companies is similar to that faced by regulated companies during RIIO-2.

However, as set out in FQ10, we consider that Ofgem should place less weight on less relevant comparators, in particular the betas of the GB water companies. Our view is that the risks faced by the water companies are very different to those faced by the GD sector, and their inclusion as beta comparators risks creating a downward bias in the beta estimation.

FQ12. Do you agree with the conclusions we have drawn from our chosen cross-checks?

We do not agree with the conclusions that Ofgem has drawn, based on a more balanced range of cross-checks.

Ofgem has stated it is important that it does not 'cherry-pick' cross-checks that provide a certain view[3], yet it appears that this is what Ofgem has done. Every cross-check has strengths and weaknesses, and all cross-checks should be treated with caution; however, we do not agree with Ofgem's decision to disregard some cross-check evidence while relying on other

[1] Kairos Economics (August 2025), Cost of equity for RIIO-3: Gas vs Electricity and MFM cross-check, page 7.
[2] Oxera (8 November 2024), Review of the regulatory regimes and business mixes for relevant European comparators to strengthen the use of European beta data. Prepared for the Energy Networks Association.
[3] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 3.97.

evidence that has clear weaknesses of its own. This presents an unbalanced picture and undermines the usefulness of cross-checks to test the CAPM-based estimate of the allowed return on equity.

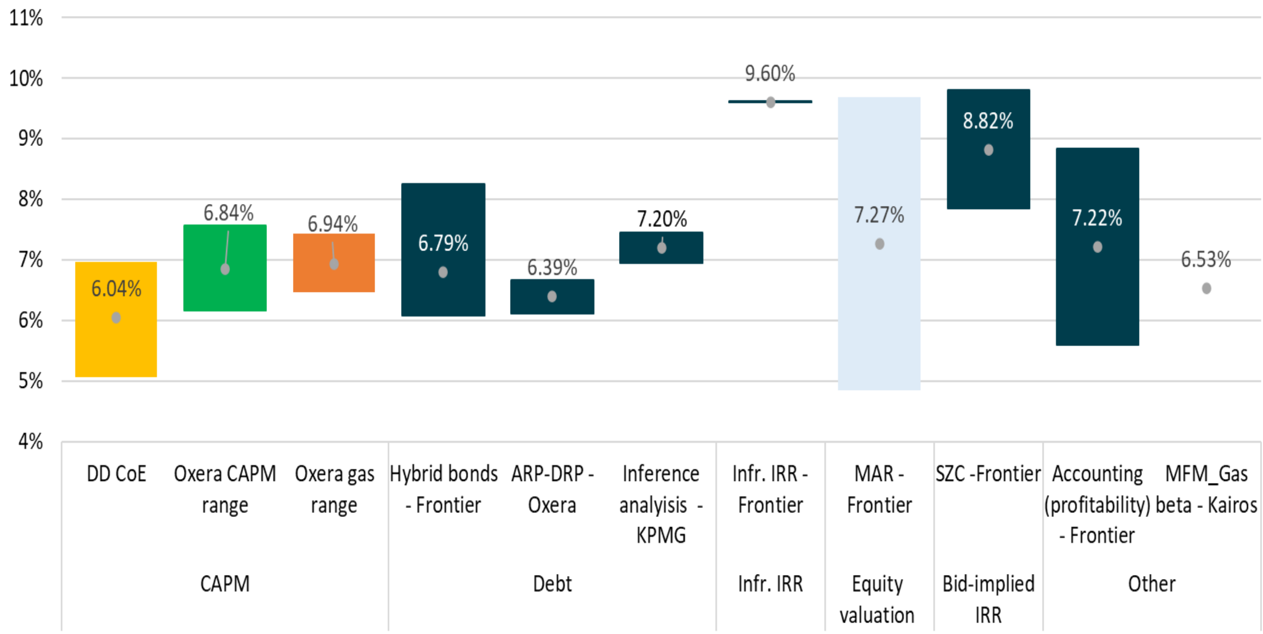
Ofgem proposes to continue to use the four cross-checks highlighted in the SSMD, i.e. Market-to-Asset Ratios (MARs), Offshore Transmission Owner (OFTO) bid implied returns, Investment Managers' TMR forecasts (which we discussed above in FQ9 on TMR) and Infrastructure Funds' implied cost of equity. Ofgem has rejected cross-checks proposed by Frontier Economics and Oxera, namely the hybrid bond cross-check, the TMR Glider, the ARP-DRP relationship, and long-term profitability benchmarking.

A new report by Frontier Economics on standards of evidence for cross-checks[1] sets out that the concerns raised by Ofgem regarding the hybrid bond cross-check are insufficient to render this cross-check uninformative, and moreover, similar concerns are present and accepted in Ofgem's own cross-checks. Ofgem's concerns in relation to the hybrid bond cross-check, for example, centre around the use of a narrow sample and the need for further assumptions to be used to derive Frontier's result. However, while Frontier has selected a preferred bond around which to anchor its results, its findings are supported by a much wider universe of hybrid bonds. And in respect of key assumptions, numerous sensitivities have been presented to inform a wider understanding of the strength of evidence.

Looking at the full set of available evidence, which now also includes (a) inference analysis carried out by KPMG; (b) estimation of the Cost of Equity using Multi-Factor Models (MFM) carried out by Kairos Economics; and (c) IRR from the Sizewell C nuclear project, Ofgem's allowed Cost of Equity appears to be inconsistent with the cross-check evidence. Ofgem's proposed Cost of Equity of 6.04% is clearly at the bottom end of the cross-check range, as shown in *Figure 7*. If Ofgem were to address the issues set out in our Business Plan and this submission, the resulting allowed Cost of Equity of c.6.5% would be better aligned with this evidence.

[1] Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks.

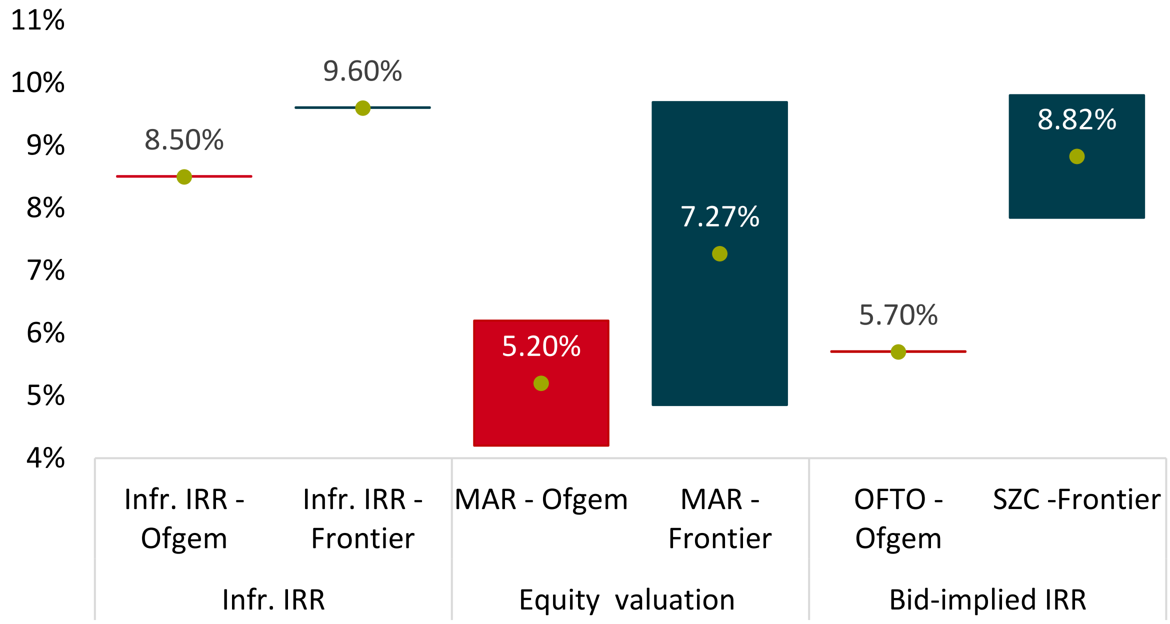
Figure 7. Summary of Cost of Equity cross-checks evidence



Source: Ofgem (1 July 2025), RIIO-3 DD Finance Annex; Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks; Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks; KPMG (August 2025), Inference analysis as a cross-check on allowed returns at GD&T3; Kairos Economics (August 2025), Cost of Equity for RIIO-3: Gas vs Electricity and MFM Cross-check. We note that Kairos Economics does not present CoE ranges in its report; the figure in the chart represents our own conservative interpretation of the findings in the report.

Where a direct comparison can be made between Ofgem's Cost of Equity cross-checks, and those of our independent advisors, these are shown side-by-side in Figure 8. The chart shows that Ofgem's cross-checks appear to be systematically underestimated.

Figure 8. Ofgem's Cost of Equity cross-checks versus Frontier's updated estimates



Source: Ofgem (1 July 2025), RIIO-3 DD Finance Annex; Frontier Economics (August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks

In the sections that follow, we discuss each of the cross-checks in turn.

Hybrid bond

Hybrid bonds are securities that combine debt and equity characteristics, meaning that they can be used to cross-check whether the allowed return on equity is sufficiently higher than the return on debt.[1]

Frontier Economics uses evidence from NGG Finance Plc's 2073 hybrid ('NGG 2073 hybrid'), and considers the spread between NGG 2073 hybrid's expected returns to next call at issuance and the senior debt benchmark yield. It then applies a scaling factor based on the assumed proportion of equity-like risk embedded in the hybrid bond. The resulting uplift is added to the current cost of debt benchmark to estimate an implied Cost of Equity.

In its latest cross-checks report[2], Frontier Economics updates its hybrid bond cross-check to reflect the latest debt benchmark index data, using the average of the iBoxx GBP A and iBoxx GBP BBB non-financial 10+ corporate indices as the debt benchmark, in line with Ofgem's

[1] Frontier Economics (2024), 'Equity Investability in RIIO-3 – A report prepared for the ENA', Section 5.
[2] Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks.

proposed DD approach to estimating the Cost of Debt. The resulting implied Cost of Equity estimate as of March 2025 is 6.1 to 8.3% CPIH-real.[1] Frontier concludes that, compared to this range, the DD proposed CoE allowance is not sufficient to mitigate investability concerns.

In its Draft Determinations, Ofgem reiterated that it agrees with the principle that the allowed return on equity should exceed the return on debt for the same asset, but raised a number of reservations about the use of hybrid bond evidence and ultimately decided not to use the hybrid bond cross-check.[2] Frontier addresses Ofgem's reservations in its report, specifically:

- **Short tenor between issuance and first call date.** Ofgem questions the equity-like classification of the hybrid bond cross-check, arguing that because hybrid instruments are typically designed to be called at the first call date, a shorter tenor makes them more akin to debt than to equity. Frontier argues that equity-likeness cannot be dismissed, because it is based on multiple characteristics (such as the option to skip coupon payments, and the subordinated nature of hybrids relative to senior debt), not just tenor. The time to first call that is used on the hybrid bond analysis is over ten years, so it is sufficiently long for the purpose of this exercise. Equity-likeness of hybrid securities is also an explicit part of the way rating agencies treat hybrid debt when reviewing companies.
- **High volatility in spreads.** Ofgem argues that the spreads observed over time have varied significantly - from 0.50% to nearly 3.0% - leading Ofgem to conclude that the volatility makes it difficult to use hybrid bond data to derive a robust implied CoE. Frontier notes that the figures quoted by Ofgem are minimum and maximum data points from a sample of 55 utility company hybrid bonds, and that 80% of the spreads in the sample were within a relatively narrow range of 100bps to 213bps. Frontier also explains that some degree of variability in the spreads of hybrids relative to senior debt is expected and reasonable.

Debt premia (ARP-DRP)

The debt premia (or 'ARP-DRP') cross-check, developed by Oxera,[3] assesses whether the differential between the asset risk premium (ARP) and the debt risk premium (DRP) is sufficient. Specifically, the ARP must always exceed the DRP at gearings below 100%. (At 100% gearing, the ARP would equal the DRP because, when a company is fully debt-financed, the claim on its assets is equivalent to the claim on its debt.)

Oxera's cross-check gives an implied minimum CoE range of 6.12% (based on a one-month averaging period) to 6.66% (five-year average)[4], significantly higher than Ofgem's proposed

---

[1] Frontier Economics (22 November 2024), Updated Cost of Equity Cross-Check Evidence. A paper for the Energy Networks Association.
[2] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 3.99.
[3] For example, see Oxera (2024), 'Cost of equity for RIIO-GD3', prepared for GB gas distribution networks, 29 November, section 4 (last accessed 1 August 2025).
[4] Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks. Table A2.1.

CoE. Oxera has also assessed whether Ofgem's proposed CoE allowance and Oxera's gas-specific CoE estimate satisfy different specifications of the debt premia cross-check. Oxera finds that Ofgem's proposed CoE fails to meet most of the specifications of this cross-check, while the midpoint of Oxera's range passes all of them. Oxera explains that the test needs to be passed in all its specifications.[1]

Oxera concludes that Ofgem's Cost of Equity allowance range is set lower than required by investors to compensate them for the additional risk of investing in equity compared to debt.

Inference analysis

Inference analysis (derived from Merton's (1974) framework and Campello, Chen and Zhang's (2008) empirical application) is founded on the premise that debt represents a relevant benchmark for investors when making investment decisions. In other words, investors compare the expected return on equity with the expected return on debt of the same company, as both provide exposure to the same underlying asset.

KPMG´s report on inference analysis[2] gives an inferred CoE range between 6.94% and 7.45%, well above the 6.04% CoE allowance proposed by Ofgem in the DD. This result may point to a material miscalibration in the allowed return on equity, which would make investment in equity disproportionately less attractive compared to debt.

MARs

Ofgem has continued to rely on Market-to-Asset Ratios (MARs) evidence at Draft Determinations. However, in contrast to its position at SSMD, it has focused on traded MARs. Ofgem used PR24 analysis published by Ofwat, which used MARs for United Utilities, Severn Trent, and Pennon, recognising that transaction premia are difficult to interpret due to a lack of information around synergies.[3] This water-company-specific MAR cross-check quoted by Ofgem indicates a cost of equity within the 4.2% to 6.2% CPIH-real range.[4]

In its cross-checks report[5], Frontier Economics notes that traded MARs also suffer from significant limitations. Cost of Equity inference based on traded MAR evidence relies on a set of stylised assumptions to draw inferences about how investors perceive the regulatory settlement, including on long-run RCV growth and outperformance. These assumptions introduce a material degree of uncertainty and limit the reliability of this cross-check.

---

[1] Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks, page 8.
[2] KPMG (August 2025), Inference Analysis as a Cross-check on Allowed Returns at GD&T3.
[3] Ofgem (2025), RIIO-3 DD Finance Annex, paragraphs 3.91 and 3.107.
[4] Ofgem (2025), RIIO-3 DD Finance Annex, Table 19.
[5] Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks.

Frontier sets out several ways in which the MARs analysis should be adapted if Ofgem is to rely on it at FD, although it notes that these refinements do not fully address the inherent limitations of the MAR cross-check.

Frontier's updated analysis of MARs evidence, as of March 2025, gives an implied CoE range of 4.85% to 9.69% (CPIH-real).

The implied CoE range derived from MARs continues to be wide, driven by variability in MARs across listed water companies. While Ofgem's proposed CoE falls within Frontier's estimated range, the breadth of outcomes and the positioning of the DD's CoE midpoint in the bottom quartile of the cross-check range suggest that Ofgem's CAPM-based point estimate is underestimating the true cost of equity.

OFTO bid implied returns

Ofgem proposes to continue to use an OFTO-based cross-check in RIIO-3. Ofgem's updated data for the latest OFTO bids (2022-2024) implies a cost of equity of 5.7% real.

We continue to consider that there are a number of weaknesses with this cross-check that limit its reliability, as set out in Frontier's equity investability report[1]:

- OFTO required return estimates are derived from investor bids. These bids may incorporate other value drivers to the bidder which are unrelated to the cost of equity, such as tax and financing structures.
- We understand that Ofgem assumed a terminal value of zero for each OFTO in its inference. However, bidders may have rationally priced in additional upside if they anticipate revenues after the contracted period.
- OFTOs operate at a much lower risk profile than regulated utilities, as their operational risk is highly limited. All OFTOs created so far have been run under the "late" model; hence, OFTOs have no construction risk. OFTOs are let for 20 to 25-year fixed term windows that provide for the full recovery of sums invested with certainty, subject to limited incentive exposure. There is also no wider regulatory/political risk, as OFTOs do not have price controls.

Frontier advises that there are other recent data points of much greater relevance, namely the bid-implied IRR of Sizewell C. This is discussed below.

Sizewell C

Sizewell C (SZC) is a project to construct a 3.2 GW nuclear power station with two European Nuclear Reactors. It is planned to be delivered at a capital cost of around £38 billion, and have a commercial operations date commencing in the mid-to-late 2030s.

[1] Frontier Economics (2024), 'Equity Investability in RIIO-3 – A report prepared for the ENA', Section 5.

Frontier Economics[1] considers that the project IRR for SZC should be included as a new and relevant cross-check in addition to, if not in place of, Ofgem's OFTO bid implied returns and the Infrastructure Fund IRR cross-check. Frontier reports that Centrica (which has a 15% stake in SZC) estimates its project IRR to be around 10% - 12% (post-tax nominal).

Frontier explains that the SZC IRR is relevant because the scale and timing of capital expenditure for this project are in line with the transmission investment required to meet Clean Power 2030 goals. The risk profile of SZC is also consistent with energy network investments, as the first nuclear build to be constructed using a RAB model that is additionally supported by a range of regulatory and commercial arrangements.

Infrastructure Funds' implied cost of equity

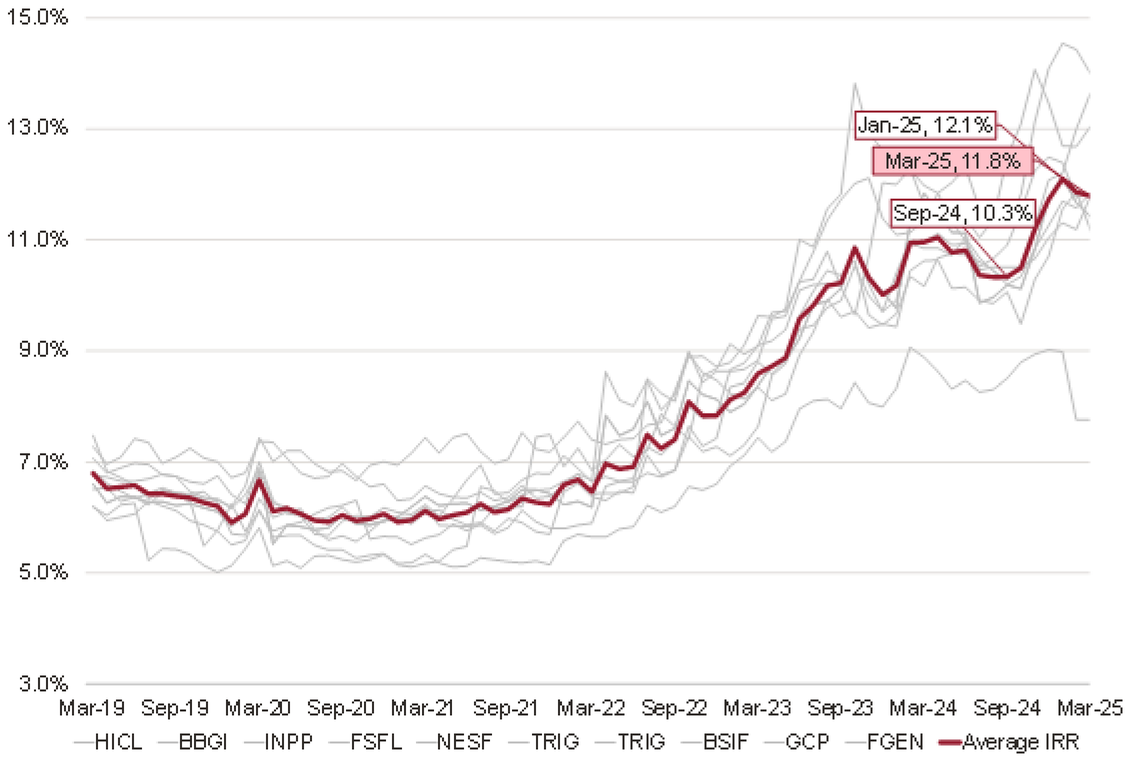
Ofgem has continued to rely on this cross-check at Draft Determinations. It reports an average implied equity IRR of 10.7% nominal (8.5% CPIH-real), based on updated data from nine infrastructure funds. Ofgem acknowledges that this figure has increased, reflecting that all funds are now trading at discounts to their net asset values. Despite the divergence between this cross-check and Ofgem's proposed Cost of Equity, Ofgem does not explain how this evidence has informed its conclusion that its cross-checks are consistent with the CAPM results.

Frontier Economics has updated its results for this cross-check[2], using the same methodology and sample of nine infrastructure funds as in its November Report.[3] We note that Ofgem is not transparent about the funds in its sample, so Frontier has not been able to replicate its approach precisely.

Figure 9 shows the general upward trend in infrastructure fund implied equity IRRs. As of March 2025, the average implied equity IRR stood at 11.8% in nominal or 9.6% in CPIH-real terms, and values in the first quarter of 2025 were consistently above 11% in nominal terms.[4]

[1] Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks.
[2] Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks, Section 3.
[3] Frontier Economics (2024), Updated cost of equity cross-check evidence – A report prepared for the Energy Networks Association, Section 3.3.
[4] Using a CPIH inflation assumption of 2%.

Figure 9. Nominal infrastructure fund implied equity IRR



Source: Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks, Figure 8.

Long-term profitability benchmarking

Profitability benchmarking can provide a useful real-world check on whether or not the allowed return for regulated companies is reasonable (or potentially too high or too low). It involves assessing how the allowed equity return compares to the outturn level of profitability for comparable businesses (i.e. businesses with a similar aggregate risk profile to energy networks).

Frontier Economics has updated this cross-check using the latest available data. This gives a range of 5.6% - 8.8%.[1]

MFMs

Kairos Economics explains that multi-factor models (MFMs) can provide a cross-check of the CAPM-estimated cost of equity.[2] Kairos sets out that the CAPM model is estimated with

[1] Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks, Section 6.

[2] Kairos Economics (August 2025), Cost of Equity for RIIO-3: Gas vs Electricity and MFM Cross-check.

considerable uncertainty and has known flaws. In particular, it is likely to suffer from omitted variable bias because it captures systematic risk through a single factor, beta. Moreover, Kairos notes the poor performance of CAPM for low beta stocks (in line with the argument set out in Oxera's report[1] and reflected in FQ10).

Kairos has carried out an analysis to estimate the Cost of Equity using MFMs. It uses the 'q factor' model to assess evidence for UK comparators, using a 10-year period of historical data. Under the q-factor model, the expected return of an asset in excess of the risk-free rate is described by the sensitivities of its returns to four factors: the market excess return, and the differences between the returns on portfolios of small and large stocks, low and high investment stocks, and high and low profitability stocks.

Kairos finds that MFMs point to a higher Cost of Equity than CAPM, with a 30bps differential on average between the q factor model and CAPM.

FQ13. Do you agree with our treatment of risks to the ET and Gas sectors as nonsystematic?

Ofgem states that it does not propose to adjust the gas sector betas for asset stranding risk because it believes that this risk is non-systematic and therefore diversifiable by investors. Ofgem says, *"[…] we did not think any additional risks identified were systematic, non-diversifiable, and therefore something that consumers should compensate investors in energy networks for. We also did not see that the European comparator evidence gave an unambiguous signal that the market awards gas companies higher betas than electric companies."*[2] Elsewhere, Ofgem also notes that *"a key assumption in the CAPM is that idiosyncratic risks can be diversified away by investors and only systematic (common) risks, such as exposure to the broader economy, require compensation in the form of return to investors."*[3]

Kairos Economics[4] has investigated whether there is a difference in systematic risk between gas and electricity networks under the CAPM by considering beta estimates of European gas and electricity companies in Ofgem's comparator set. Kairos observes a difference in the estimates of the asset betas of gas and electricity portfolios of c. 0.02-0.03, indicating that there is a difference in systematic risk between gas and electricity networks under the CAPM. Using Ofgem's DD CAPM parameters, this amounts to a 24 - 37 bps impact on the CAPM Cost of Equity.

In any case, regardless of whether Ofgem considers stranding risk to be systematic or not, it is clear that the GD sector faces a material and real-world risk of asset stranding. Investors will require a sufficiently higher return to compensate for this higher level of risk, both for equity and debt. While we appreciate that the CAPM is an important tool for estimating the

[1] Oxera (22 August 2025), RIIO-GD&GT3 Cost of Equity and Debt Premium Cross-check. Prepared for Future Energy Networks.
[2] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 3.62.
[3] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 3.81.
[4] Kairos Economics (August 2025), Cost of Equity for RIIO-3: Gas vs Electricity and MFM Cross-check.

allowed return on equity, it is important to recognise that it is only a model, and in fact, not all investors use this model. Ofgem should therefore ensure that investors are sufficiently compensated for stranding risk, whether this is through the beta or through a separate adjustment to the allowed return on equity.

The impact of stranding risk on investor appetite can clearly be observed in the debt market – for example, the KPMG debt investor survey report[1] showed that debt pricing for gas networks is wider than equivalent debt pricing for electricity networks and debt tenors available to gas networks have shortened compared to electricity networks, with lending appetite for gas now generally limited to 15 years or less. In fact, even Ofgem's own sample of gas bonds, used in its estimation of GNP, has an average tenor of around 12 years.[2] More recently, NERA has shown that investors expect a gas network premium of c. 45 bps for new issuance compared with the iBoxx A/BBB benchmark index proposed by Ofgem.[3]

It is not possible to directly observe the required CoE premium in the same way in the equity market, but Ofgem has not provided any evidence that such a premium does not exist. We also note that, as set out in FQ12 in relation to Merton's (1974) framework, we can assume that investors compare the expected return on equity with the expected return on debt of the same company, as both provide exposure to the same underlying asset. It is therefore reasonable to expect that debt market evidence of a premium for gas networks will also be reflected in a higher required return for equity investors.

We also note that credit rating agencies have materially tightened credit ratio thresholds for the GD sector, driven by a perception of increased risk in the gas sector. As we set out in more detail in FQ18, S&P has recently stated that it expects *"a gradual reduction in residential and industrial gas demand in the U.K. over the next decades from 2030. At the same time, uncertainties persist in relation to the potential repurposing of the gas distribution networks (GDNs) in the future and the potential pick-up of renewable gases investments."*[4] Similarly, Moody's has stated that, *"We see higher business risk for gas networks than electricity because gas network use will ultimately decline, whereas electricity networks are growing in support of the energy transition. The additional uncertainty associated with the detailed pathway and timeline to net zero means that GB gas networks will have to exhibit a stronger financial profile to maintain existing credit quality."*[5]

---

[1] KPMG (11 April 2024), Perception of risk for Gas Distribution Networks (GDNs) under RIIO-3 and beyond: debt investor survey. Prepared for the GDNs. (Confidential.)

[2] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks, page 5.

[3] NERA (19 August 2025), Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3. A report for the gas networks.

[4] S&P Global (29 July 2025), Four U.K. Gas Distribution Networks Ratings Affirmed Following Regulatory Draft Determinations; Outlooks Stable.

[5] Moody's (29 July 2025), Gas Networks – Great Britain. Broader policy uncertainty on energy transition increases business risk.

Stranding risk is clearly having a tangible impact on investors' appetite to invest in the GD sector.

Ofgem argues that it has *"acted to mitigate the perception of asset stranding risks in GD by accelerating depreciation - effectively increasing the speed at which investors recover previously invested funds and reducing upward pressure on average bills in the medium term. We considered this mitigation of perceived risk more suitable than pre-emptive increases to allowed returns on equity."*[1]

While we welcome Ofgem's decision to accelerate depreciation, we reiterate the point made in our Business Plan that any adjustment to regulatory depreciation can only ever partially mitigate stranding risk. Stranding risk cannot be entirely removed because scenario uncertainty will remain, and the pace of technological change, policy change and customer behaviour change is all highly uncertain. It is therefore necessary to not only mitigate but also compensate for the risks borne by debt and equity investors.

As we set out in our Business Plan, we undertook analysis to estimate the cost of equity that would be required to compensate investors for the probability-adjusted risk of asset stranding, after taking account of accelerated depreciation. The analysis is based on the principle that, because asset stranding is (at least in part) an asymmetric risk, it exerts downward pressure on expected returns. Therefore, investors need to be compensated for this, either directly through the CAPM model (through a gas-specific beta that reflects stranding risk) or through an appropriate uplift to the allowed return.

The analysis estimates the required Cost of Equity, which would be necessary to compensate investors for the probability-adjusted risk of asset stranding. The approach involves the following steps:

- **Step 1:** Develop a projection of long-term cash flows under a plausible low gas demand scenario.
- **Step 2:** Calculate the achieved Internal Rate of Return (IRR) of investors in this scenario, assuming that stranding arises – e.g. if bills are constrained (therefore giving rise to some unrecovered revenue); and/or a proportion of the closing RAV becomes unrecoverable.
- **Step 3:** Calculate an allowed CoE uplift that would be required to make investors whole in this scenario.
- **Step 4:** Apply a probability assumption to this scenario arising, in order to estimate a probability-adjusted required uplift to the Cost of Equity.
- **Step 5:** Apply this uplift to the Cost of Equity for a 'vanilla' energy network, hence avoiding double-counting.

Having updated this analysis for FES 2025 gas demand pathways and Ofgem's DD assumptions on the proposed financial package (without prejudice to our position on its elements), we find a required cost of equity of c. 6.3% (based on the FES Hydrogen Evolution pathway – which is

[1] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 3.83.

the pathway with highest gas demand while remaining compliant with Net Zero – coupled with the "Cautious Acceleration" approach proposed in our Business Plan); increasing to c. 6.5% (assuming other FES scenarios with lower gas demand and fewer gas customers, coupled with Ofgem's proposed depreciation Option 4).

In conclusion, regardless of whether asset stranding risk is systematic or not, it is essential to compensate investors for this risk. If the risk is viewed as being purely systematic, then it needs to be reflected in the beta by ensuring that only relevant gas comparators are used to estimate the beta for the GD sector. If the risk is viewed as being non-systematic, then this should be compensated outside the CAPM framework. Both approaches indicate a cost of equity estimate higher than Ofgem's DD point estimate of 6.04%, and more in line with our suggested figure of approximately 6.5%.

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

No, we do not agree with Ofgem's proposed dividend allowance policies for the notional gas company.

Ofgem has decided to maintain the same 3% base dividend yield used in RIIO-2. We reiterate our view that this dividend yield is significantly lower than even the base allowed return on equity of 6.04%, let alone a more appropriate estimate of c.6.5%, and is therefore clearly insufficient.

Ofgem's 3% dividend yield implies deferring a significant part of the allowed equity return to shareholders, which is incompatible with the current context of the GD sector. Unlike fast-growing industries where deferring dividends may be acceptable due to expected growth in future equity returns, the gas distribution sector faces long-term uncertainty and no sustained RAV growth as the UK moves toward Net Zero. This is in contrast to the ET sector, where Ofgem has stated that, *"We see substantial value for investors in the anticipated growth in the RAV in ET and that growth will increase dividend potential in the future. Dividend growth, which will match RAV growth, could range between 14% and 30% on a compound annual growth basis over RIIO-3."*[1] Despite this very different context and growth potential in ET, Ofgem has set the same 3% dividend yield for GD as for ET.

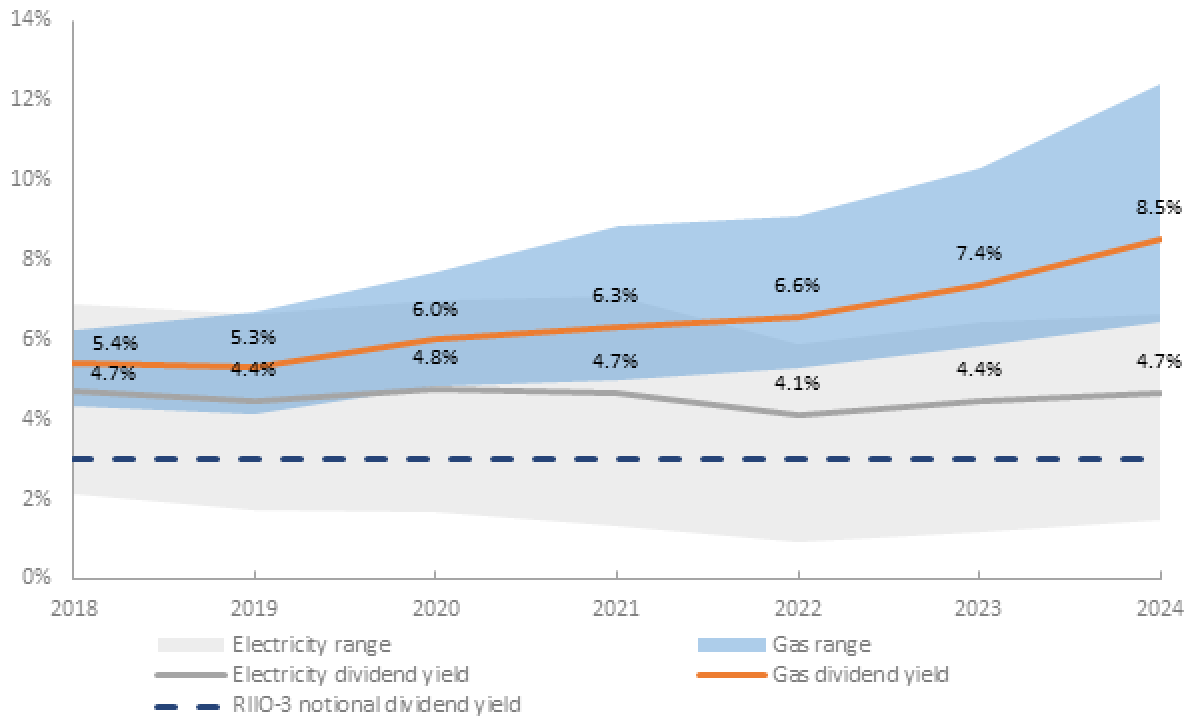
Indeed, if a decrease in the GD sector's RAV is expected in the long run, then there should be a return of capital back to the investors, over and above the full payment of allowed equity returns in the form of dividends. In particular, accelerated depreciation aims to return the RAV to investors faster than under the status quo. As explained by Oxera[2], this should, by definition, lead to higher distributions back to equity holders, as otherwise, additional cash available in the short to medium term, which Ofgem assumes would mitigate stranding risk,

[1] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 3.109.
[2] Oxera (20 August 2025), Dividends in RIIO-GD3. Prepared for Future Energy Networks (FEN).

is trapped in the business by this artificially low assumption of the dividend yield for the notional gas company.

As we set out in our Business Plan, the Oxera GDN dividends report[1] assessed empirical evidence on dividend yields and payout ratios of traded European gas and electricity networks. Oxera has updated this analysis[2], adding data from 2024. According to this updated evidence, dividend yields for European gas companies ranged between 5.3% and 8.5% over the period 2018–24, compared to dividend yields for electricity companies, which ranged between 4.1% and 4.8%. This analysis shows that gas dividend yields have continued to increase, rising from 5.3% in 2019 to 8.5% in 2024. Meanwhile, electricity dividend yields have remained broadly stable, fluctuating between 4.1% and 4.8%.

Figure 10. Dividend yield of European listed gas and electricity networks



Source: Oxera (20 August 2025), Dividends in RIIO-GD3. Prepared for Future Energy Networks (FEN).

These trends align with the view that dividends need to be higher in the gas sector to reflect lower RAV growth and faster asset depreciation.

Oxera also explained in its original report that, for the purpose of financeability assessment, assumptions need to be consistent between RAV growth, gearing, cost of capital and dividend yield. In particular, "*a higher dividend yield is necessary to maintain the gearing at or around*

[1] Oxera (3 December 2024), Gas distribution networks' dividends in RIIO-GD3. Prepared for GB gas distribution networks.

[2] Oxera (20 August 2025), Dividends in RIIO-GD3. Prepared for Future Energy Networks (FEN).

the notional assumption, as higher distributions to shareholders would counterbalance the downward pressure that the introduction of accelerated depreciation (and lower RAV growth more generally) would put on the GDNs' gearing."[1]

Although Ofgem references this evidence in the DD, it does not appear to properly engage with it. It provides no response to Oxera's evidence of higher dividend yields for European gas networks. With respect to the impact on gearing, Ofgem states that *"During RIIO-3 there may be downward pressure on gearing in the GD sector but with options still under consideration it would be premature to change the allowed notional company dividend yield at this stage. Our working assumption is to maintain the 3% of equity RAV as the base case assumption for the dividend yield, that was used in RIIO-2. One proposal to consider would be the allowance of special dividends were gearing to reach a certain level. This could be symmetric with the assumption that the notional company raises equity if gearing deviates from its assumed level."*[2]

We welcome Ofgem's recognition that there is likely to be downward pressure on gearing in the GD sector during RIIO-3, driven by accelerated depreciation and lower RAV growth more generally. However, in our view, creating new arrangements around "*special dividends*" creates unnecessary regulatory complexity and rigidity. We also note that the terminology around "*special dividends*" may create an impression of intransparency and a temporary, ad hoc nature of this arrangement. Therefore, we encourage Ofgem to use clearer wording, such as "*constant gearing dividends*", which it has used elsewhere, or "*return of capital*".

We agree with Oxera's observation[3] that changes in the economic and regulatory environment – such as accelerated depreciation and less investment opportunities in the gas sector – are likely to persistently increase the cash available for distribution over RIIO-GD3 and beyond. Hence, it would be more appropriate to distribute the excess cash to shareholders via higher recurring dividend payments rather than via "*special dividends*" that are often linked to temporary excess cash or non-recurring cash inflows.

We observe that in the draft RIIO-GD3 BPFM ('Finance&Tax' tab, rows 126-127) Ofgem appears to implement a threshold for the payment of constant gearing dividends of 5 percentage points below the notional gearing level. That is, gearing needs to fall below 55% in order to trigger the payment of constant gearing dividends. We do not agree with the implementation of such a threshold, and our view is that constant gearing dividends should be payable as soon as gearing falls below 60%.

The use of such a threshold creates artificial lumpiness in the cash flows of the business, driving unnecessary instability in gearing levels. It also creates unnecessary distortions in the financial modelling and takes the notional company further away from the real-world financing arrangements. Moreover, the approach can lead to a higher initial tax allowance when notional gearing dips below 60%, but is likely to trigger the tax clawback mechanism

[1] Oxera (3 December 2024), Gas distribution networks' dividends in RIIO-GD3. Prepared for GB gas distribution networks, page 4.
[2] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 3.110
[3] Oxera (20 August 2025), Dividends in RIIO-GD3. Prepared for Future Energy Networks (FEN).

later when a significant amount of additional debt is eventually raised by the notional company to restore gearing to 60%. This would drive a widening wedge between notional and actual company accounts without any good justification. Furthermore, Oxera[1] explains that restraining dividend payout when there is free cash flow at the notional gearing level effectively increases the duration of the cashflow stream for the equity holders, and can make the IRR lower than the intended allowed equity return, all else being equal. As far as we can see, there are no countervailing benefits to implementing a threshold. It does not lower customer bills, and does not avoid administrative costs or burden as dividends are paid annually.

We understand that Ofgem appears to consider the payment of '*special dividends*' as being symmetric with assumptions around the trigger for the cost of issuing equity. We recognise that there is a 5% threshold for equity issuance; however, the same rationale does not apply to dividend payments. There are genuine costs associated with equity issuance, and therefore, such events should be limited in frequency (as smaller equity requirements can be managed through retained earnings). Dividend payments, on the other hand, do not have equivalent administrative costs, and there is therefore no reason to limit their frequency if the objective is to maintain a constant level of gearing. The best way to maintain a constant level of gearing is to allow the dividend level to be the balancing figure for the target gearing level each year, instead of assuming an artificially low fixed dividend level and letting gearing fluctuate within a band with no clear benefit.

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

We do not have a view on Ofgem's proposal not to apply the flat WACC approach, as this does not affect gas networks.

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

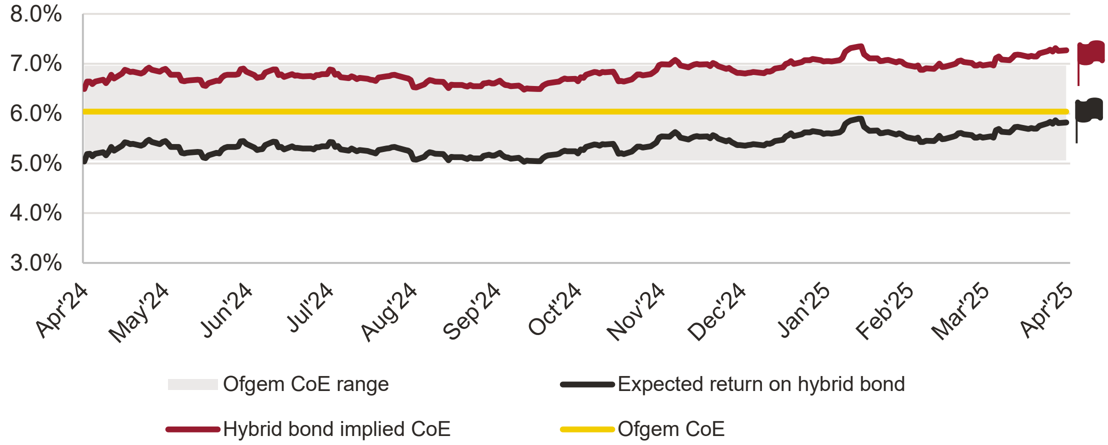
We welcome that Ofgem has acknowledged some of the evidence put forward by the networks and made some positive movements to address some of the issues that we identified in its SSMD beta and TMR estimates.

However, as set out in our responses above, we have remaining concerns around Ofgem's approach. Ofgem's resulting CoE is towards the low end of the wide range of cross-checks set out in our response to FQ12, and the bottom half of Ofgem's CAPM range fails an important rationality test, because it is lower than the expected return from the representative hybrid bond, as shown in Figure 11 extracted from Frontier's cross-checks report[2].

[1] Oxera (20 August 2025), Dividends in RIIO-GD3. Prepared for Future Energy Networks (FEN).

[2] Frontier Economics (22 August 2025), Cross-check Standards of Evidence. A Report Prepared for the Energy Networks Association and Future Energy Networks.

Figure 11. Rationality check against Ofgem's CoE range



Source: Frontier Economics (22 August 2025), Updated Cost of Equity Cross-Check Evidence. A report prepared for Future Energy Networks, Figure 3.

An investor would have to be irrational to want to invest in network equity if they can get a similar (or higher) return from a hybrid bond (which is half debt). As of the end of March 2025, as shown in Figure 11, almost the entire bottom half of Ofgem's DD CoE range falls into this "black flag" category. We therefore consider that Ofgem's proposed CoE continues to create risks to investability.

We remain of the view that an allowed cost of equity of at least c. 6.5% (updating our Business Plan figure of 6.36% to reflect movement in ILG yields) would serve as an appropriate and investable return, as it is better aligned with evidence from financial markets and the risks that the GD sector faces on the path to Net Zero.

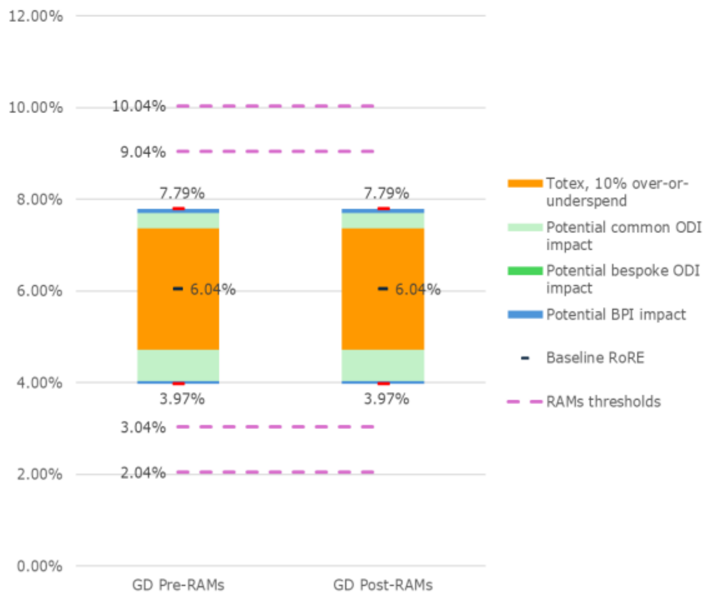
Furthermore, in addition to setting an appropriate level of baseline allowed equity returns that adequately reflects the capital market environment, for the RIIO-GD3 financial package to be investable, the operational and incentives package also needs to be calibrated in a way that investors find attractive. However, we are concerned that the Totex and ODI incentives package proposed in DD has significant downside risks for the notional GDN (we discuss this in more detail in our response to FQ17) and therefore is likely to contribute to further challenges in relation to the investability of the proposed RIIO-GD3 financial package.

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

We do not agree with Ofgem's assumption that there is risk symmetry within the aggregate balance of the whole price control. In our view, the balance of risk is skewed to the downside for a notional GDN.

First, it is important to state that the RoRE ranges shown in the DD are highly simplified and are broadly symmetric by design. The ranges for GD are replicated in Figure 12.

Figure 12. RIIO-GD3 average RoRE ranges, as reported in the DD



Source: Ofgem (1 July 2025), RIIO-3 DD Finance Annex, Figure 2

The symmetric upside and downside for Totex is driven purely by the symmetric input assumptions of 10% out- and under-performance that Ofgem has used. Ofgem has not considered the probability of network companies achieving these levels of out-/under-performance, and whether the probability of outperformance is equal to the probability of underperformance. As set out in our response to Ofgem's DD (GD Annex)[1], we consider that the proposed allowances set out in the DD represented a material shortfall for NGN, meaning that expected Totex performance is skewed to the downside.

Ofgem's Ongoing Efficiency challenge is an example of the drivers of downside risk in Totex, and one which affects all three network sectors. While there is uncertainty around the level of productivity growth that can be achieved by the networks over RIIO-GD3, Ofgem's 1% challenge is materially higher than the evidence, and is even in the top quarter of the range proposed by its own consultants, Grant Thornton, of 0.1% - 1.3%. Notwithstanding our view that the higher end of this range lacks any credibility and we consider that Ofgem have made errors in setting the OE challenge[2], even if we assume the distribution of potential productivity growth was evenly distributed along this range, and unadjusted Totex allowances were set at an appropriate level, companies would be expected to underperform their Totex allowances 75% of the time.

[1] NGN (2025), RIIO-GD3 Draft Determination Consultation Response, GD Annex, Questions 35, 36.
[2] NGN (2025), RIIO-GD3 Draft Determination Consultation Response, Overview Document, Question 19.

Ofgem's RoRE chart does appear to show that there is more potential downside than upside for GDNs from ODIs. However, these RoRE ranges are based on caps and collars and do not show the likelihood of performing at these levels. Ofgem is proposing to materially tighten targets for a number of ODIs at RIIO-3, reducing the likelihood of upside.

We commissioned Frontier Economics to undertake a Monte Carlo simulation analysis[1] of the risk balance of the RIIO-GD3 price control package proposed in the Draft Determinations. Monte Carlo simulations are used to model the probability of different outcomes in a process that cannot easily be predicted, e.g. due to the existence of random variables or shocks. They involve running a large number of simulations of possible outcomes for one or more variables, based on a specified expected mean value for each variable, and a probability distribution of potential variation around the mean.

To carry out this analysis, Frontier has identified the relevant drivers of out-/under-performance from RIIO-GD3 DD, and developed appropriate assumptions based on Ofgem's proposed incentive design and historical data on performance.

Frontier finds that the skew of plausible outcomes is clearly to the downside, with a notional GDN expected to underperform by 47 bps of RoRE relative to the baseline allowed return on equity, on average. The range of outcomes in which a notional GDN is expected to perform 90% of the time ranges from -1.78% to 0.84%, showing that there is more scope for downside than upside in the price control. These findings support our view that the price control package set out in the DD is asymmetrically calibrated.

Frontier recommends that Ofgem (a) revisit its approach to setting Totex allowances (e.g. the use of the 85th percentile) to ensure that companies are appropriately funded to deliver at RIIO-GD3; (b) consider whether some of the asymmetric mechanisms in the price control can be made more balanced, or scaled down; and (c) consider the impact of this inbuilt downside on investability of the finance package.

Debt Financeability questions

FQ18. Do you agree with our approach to assessing financeability?

We agree with Ofgem's proposal to target a minimum credit rating of Baa1/BBB+. NGN has chosen to target a credit rating at this level since our incorporation, as it enables us to raise efficient finance and strengthens financial resilience by providing headroom to absorb adverse shocks.

We also agree that Ofgem should reflect the key methodologies used by credit rating agencies (CRAs) in its financeability assessment, along with other relevant information that informs credit opinions.

[1] Frontier Economics (22 August 2025), Expected performance modelling for RIIO-GD3.

Importantly, as set out in FQ13, CRAs are materially tightening credit ratio thresholds, driven by a perception of increased risk in the gas sector. This needs to be reflected in Ofgem's financeability assessment.

Specifically, S&P has stated that it expects *"a gradual reduction in residential and industrial gas demand in the U.K. over the next decades from 2030. At the same time, uncertainties persist in relation to the potential repurposing of the gas distribution networks (GDNs) in the future and the potential pick-up of renewable gases investments."*[1] It therefore no longer views GDNs as operating at the lower end of the utility risk spectrum, and will apply credit ratio thresholds for '*medial volatility*' rather than '*low volatility*', meaning it will require stronger financial metrics for a given rating level. In particular, S&P has stated that thresholds for FFO/Net Debt for operators with BBB+ credit ratings will likely increase from >9% currently to >13%.[2]

Similarly, Moody's has stated that, *"We see higher business risk for gas networks than electricity because gas network use will ultimately decline, whereas electricity networks are growing in support of the energy transition. The additional uncertainty associated with the detailed pathway and timeline to net zero means that GB gas networks will have to exhibit a stronger financial profile to maintain existing credit quality."*[3] Moody's estimates the following required improvements in financial ratios for a Baa1-rated gas network company in Great Britain[4]:

- Adjusted Interest Coverage Ratio (AICR) to increase from 1.4x to 1.6x; and
- Net Debt/RAV to decrease from a maximum of 75% gearing to 72%.

Ofgem's assumptions and thresholds will need to be aligned with revised thresholds to ensure the accuracy and robustness of its financeability assessment.

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?

We do not have a view on this question as it is not relevant for the gas distribution sector.

---

[1] S&P Global (29 July 2025), Four U.K. Gas Distribution Networks Ratings Affirmed Following Regulatory Draft Determinations; Outlooks Stable.

[2] S&P Global (29 July 2025), Four U.K. Gas Distribution Networks Ratings Affirmed Following Regulatory Draft Determinations; Outlooks Stable, page 2.

[3] Moody's (29 July 2025), Gas Networks – Great Britain. Broader policy uncertainty on energy transition increases business risk.

[4] Moody's (29 July 2025), Research Announcement: Moody's Ratings: Energy transition policy uncertainty for gas networks in Great Britain requires stronger financial profiles.

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

We welcome Ofgem's proposal to incorporate long-term modelling into its financeability assessment, particularly given that financeability results for the GD sector are driven by two significant policy changes relative to RIIO-GD2: accelerated depreciation and the semi-nominal Cost of Debt allowance. Both of these policies bring forward cash flows and thereby improve the financial ratios for RIIO-GD3. As recognised by Ofgem, it is important to identify long-term structural trends, as they may be best addressed within the RIIO-3 framework, rather than deferred to subsequent periods.

Ofgem's long-term modelling results, as reported in the DD, do not appear to show any long-term financeability issues for the GD sector. However, Ofgem has not shared its underlying assumptions or analysis with companies, nor has it had an opportunity to factor in the updated credit ratio thresholds discussed in our response to FQ18. Finally, long-term modelling is inherently imprecise and assumption-driven, particularly when future policy decisions cannot be known or forecast with any level of accuracy. We therefore encourage Ofgem to engage with companies on its analysis, assumptions, and the scenarios that it has tested, to ensure that the conclusions from the analysis are robust.

Financial resilience questions

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

We do not agree with Ofgem's proposals in relation to financial resilience, with particular reservations about Measure 3 outlined below.

We recognise Ofgem's desire to ensure the financial resilience of the sector and protect consumers. Specifically, Ofgem proposes to retain existing financial resilience provisions from RIIO-GD2, and strengthen three measures:

- **Measure 1:** Amend the 'Credit Rating of the licensee and related obligations' 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 2:** Amend the 'Indebtedness conditions' to include an additional distribution lock-up trigger when the licensee reaches 75% Regulatory Gearing, alongside the existing trigger when the licensee reaches a credit rating of BBB- with a Negative Watch/Outlook. The triggers are to be both backwards-looking (based on the actual regulatory gearing as reported at the closing of the last reporting year) and forward-looking (based on projected gearing for the end of the current reporting year).
- **Measure 3:** Amend the 'Availability of Resources (AOR) obligations' to require licensees to state that, based on the agreed assumptions, they have sufficient financial resources to cover the entire price control period or a minimum of three years ahead. Additionally, the

certificate in relation to financial resources would have to include references to stress testing analysis undertaken prior to the licensee issuing the certificate.

We consider that the measures in place in RIIO-GD2 are adequate to provide Ofgem with oversight and assurance that regulated entities are financially resilient and have sufficient resources to maintain such resilience. Ofgem has not provided evidence that the current license conditions aimed at ensuring financial resilience are not effective. Some of the measures Ofgem is proposing would introduce burdens (detailed below) that go further than other regulatory regimes (such as the water sector) and could affect investor appetite and result in additional costs compared with RIIO-GD2.

If Ofgem wishes to take these proposals further, a proper impact assessment should be carried out. Ofgem should ensure that it does not impose additional costs on customers which are not justified by associated benefits.

Furthermore, if Ofgem does proceed with these proposals, it must also provide comprehensive guidance to companies, setting out how they can ensure compliance.

Below, we address each of the three new measures that Ofgem has proposed in turn.

Measure 1 – requirement for a minimum of two investment-grade credit ratings

NGN already maintains two investment-grade credit ratings, and it is unlikely that this change would result in any direct impact on NGN or our customers.

That said, if it is to become a Licence condition for a network operator to maintain investment-grade credit ratings from at least two agencies, it will become even more critical that the overall price control settlement supports this from a financeability and investability point of view. As set out in our response to FQ18, CRAs are materially tightening credit ratio thresholds, which need to be reflected in Ofgem's financeability assessment.

Measure 2 – introduce an additional dividend lock-up trigger of 75% gearing

NGN is not currently close to the gearing threshold and has an internal upper threshold for gearing of 70%. We therefore expect it to be highly unlikely that NGN will find itself subject to any of the two dividend lock-up trigger events. However, we consider that existing protections in the licence work and, to our knowledge, there has not been evidence of a potential financial resilience issue in the energy network sector.

This proposal should be considered in the context that Licensees' ability to increase leverage is already directly restricted through their respective bank covenants and also implicitly constrained via the tax clawback trigger mechanism, which removes any incentive to over-leverage by clawing back the tax benefit a Licensee is assessed to have obtained as a result of gearing levels and interest costs that are higher than assumed.

However, we also note that given the potential for the GD sector RAV to decline in the longer term, combined with a lumpy debt issuance profile for infrequent issuers such as NGN, could create a risk of triggering a lock-up in individual years. This could send unnecessary negative signals and an impression of financial instability to investors, and increase the true cost of equity as a result.

Measure 3 – Availability of Resources (AOR) certificate to cover the entire price control period or a minimum of 3 years ahead

We strongly disagree with this proposal, and in our view, Ofgem has not made the case that this is needed.

Currently, Standard Special Condition A37 requires, among other things, that each year Licensees provide Ofgem with a Certificate, approved by the Board of Directors, confirming whether it has sufficient financial resources such that it can continue carrying on its business for the following 12 months.

While Ofgem states that it does not "*consider that licensees are required to increase liquidity beyond current levels*", that it "*does not expect pre-funding the entire price control period*" and "*companies already plan to ensure adequate resources are available for periods longer than 12 months as part of their normal business planning cycles*"[1], we consider that this new requirement is still far more onerous than the current requirements and is likely to involve additional costs to consumers in practice. We are particularly concerned about the cost implications that the introduction of this obligation could result in reality, given that earlier pre-financing is likely by a Licensee adopting a prudent approach, whether or not it is strictly "*required*" or "*expected*" by the regulator. Moreover, for a Licensee to receive a Board-level certification that it has sufficient financial resources to cover a period greater than twelve months, it would need to at least have fully committed funding in place (which is not cost-free) to cover all expected obligations in that period, with headroom.

This requirement could also span two price control periods. This creates an additional challenge in certifying that sufficient financial resources are available, without having knowledge (let alone certainty) of Ofgem's policy decisions for the upcoming price control.

Ofgem's further proposed requirement, with references to stress testing, further complicates forecasting requirements. If this requirement is maintained, Ofgem must, at a minimum, provide robust guidance on the methodology that networks are expected to adopt for stress-testing.

Overall, we consider that the cost implications of this proposal could be significant (including, ultimately, for customers) and are likely to bring little to no countervailing benefit to consumers.

Finally, Ofgem's RIIO-3 proposals for financial resilience go materially further than the established requirements in the water sector, even though sector-wide financeability risks are more acute in water. For example, Ofwat's distribution lock-up is triggered only by loss or deterioration of investment-grade credit ratings. Ofgem, by contrast, would introduce a trigger (locking up distributions where actual or forecast regulatory gearing reaches or exceeds 75%) even if credit ratings remain unchanged. Regarding financial resilience, Ofwat requires water companies to certify they have sufficient resources for the upcoming twelve months. Ofgem would extend this timeframe significantly, requiring licensees to certify

[1] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 6.26.

sufficiency for a minimum of three years (or the entire price control period), with added requirements to include stress testing and downside scenario analysis.

Corporation Tax 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?

We agree with Ofgem's position that a tax forecasting penalty is not required.

FQ23. Do you agree definitions for ANDt and TDNIt should be updated to reflect the principles outlined in paragraph 7.41?

We agree that the definitions for ANDt and TDNIt should be updated to reflect the principles outlined in paragraph 7.41.

Regulatory Depreciation Questions

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?

Ofgem has proposed to take forward accelerated depreciation Option four: *"maintaining the existing depreciation profile for RAV outstanding at the end of RIIO-2 and depreciating new additions to the RAV during RIIO-3 and onwards on a sum-of-digits basis with the assets depreciated to zero by the government's Net Zero target date, which is currently 2050."*[1]

We welcome Ofgem's decision to accelerate depreciation, which confirms Ofgem's agreement with the direction of travel proposed in NGN's Business Plan. As set out in our Business Plan, Ofgem's position in the SSMD to adopt Option 1 (depreciating all RAV by 2050) was, in our view, premature and excessive. We proposed a more balanced and straightforward alternative: to shorten all asset lives to 35 years for RIIO-GD3, with a view to revisiting this profile for RIIO-GD4.

That said, the approach adopted by Ofgem in the DD seems like another sensible compromise aimed at managing the asset stranding risk in a proportionate way, and balancing the interests of present and future customers, given the uncertainties surrounding the Net Zero transition.

However, as set out in our Business Plan, regardless of the precise depreciation trajectory chosen, it is important to recognise that without the Government underwriting GDNs' RAV in full, accelerated depreciation can only ever partially mitigate stranding risk. This is because even with accelerated depreciation, Ofgem's SSMD modelling showed significant bill

[1] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 8.9.

increases are required in the 2040s under some FES pathways – raising questions about the feasibility of whether required revenues can be recovered in the long term in those scenarios. Further, the profile of gas demand and the rate of decline of the consumer base is fundamentally uncertain – the market may evolve faster (or slower) than currently anticipated in the FES pathways.

Therefore, it is important that Ofgem recognises and remunerates stranding risk in the allowed CoE, either through an appropriate gas-specific estimate of the beta CAPM parameter and/or by acknowledging that asset stranding risk may have an asymmetric element that must be remunerated via a cost of equity uplift, as suggested in our Business Plan submission and our response to FQ13 above.

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

We do not have a view on this question as it is not relevant for the gas distribution sector.

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

We do not have a view on this question as it is not relevant for the gas distribution sector.

Return Adjustment Mechanisms Questions

FQ27. Do you agree with our proposals for the RAM thresholds and adjustment rates?

Given that Ofgem is minded to retain the Return Adjustment Mechanism (RAM), we do not see any compelling reason to change the RIIO-GD2 RAM thresholds and adjustment rates.

However, as set out in our SSMC response, and originally in our response to RIIO-GD2 Draft Determinations, we believe that adjusting returns ex-post can be harmful to consumers in principle if it affects Licensees' incentives and undermines investor confidence.

A RAM, as an extra failsafe measure, should be unnecessary with a correctly calibrated price control. There are several measures already contained within the regulatory framework which are designed to protect consumers, including the Totex Incentive Mechanism (TIM), the Business Planning Incentive (BPI), uncertainty mechanisms (UMs), Output Delivery Incentives (ODIs), and Price Control Deliverables (PCDs). These are all intended to ensure that consumers are receiving value for money and are protected from uncertainty.

The RAM risks dampening Licensees' incentives to make further efficiencies beyond the threshold, by effectively halving the returns beyond the primary threshold and almost entirely removing them beyond the second. The converse is true for underperformance beyond the thresholds, which means that the higher the level of Totex overspend or ODI under-delivery, the higher the cost customers will have to bear.

In our view, the risk of reducing Licensees' incentives to maximise efficiency (which should be at the centre of an effective regulatory regime), combined with the complexity that RAMs add to the regulatory framework, can harm consumers over the longer term.

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

We do not have a view on this question as it is not relevant for the gas distribution sector.

Indexation of Regulatory Asset Value Question

FQ29. Do you agree with our proposals for RAV Indexation?

Given Ofgem's decision to adopt a semi-nominal WACC, we agree that, for consistency, it is appropriate to index only the portion of the RAV that corresponds to the notionally assumed share of equity and index-linked debt, while the remainder is de-linked from inflation. We agree with the mathematical approach that Ofgem has proposed to implement this and look forward to receiving further details from Ofgem on how it proposes to treat RIIO-GD2 closing RAV, in order to ensure that the closing balance of RIIO-GD2 reflects the full year's inflation for 2025/26.

Other Finance Issues Questions

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

Ofgem has proposed to retain two capitalisation rate "*buckets*" in line with the approach followed in RIIO-GD2: Bucket 1 for ex-ante allowed Totex is company specific; and Bucket 2 for re-openers and volume drivers is uniform for each sector.

Ofgem's approach to setting capitalisation rates is adequate. We agree that capitalisation rates should broadly reflect the actual split of capital expenditure and operating expenditure expected over the price control – i.e. using the average '*natural*' capitalisation rate over the price control. This approach ensures that charges over time reflect actual expenditure and are therefore fair to both existing and future consumers.

With regard to the specific estimates provided by Ofgem for the Bucket 1 capitalisation rate, we note that the value of 27% was incorrect (as acknowledged by Ofgem in response to a DDQ). The average value of 24.05%, as set out in the published BPFM, was more appropriate. However, we recognise that this figure will be revised in the Final Determinations, once final Totex allowances are confirmed.

We cannot comment on Ofgem's decision on capitalisation rate Bucket 2 as it will be published in the Final Determination.

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

We agree with Ofgem's proposal to retain the RIIO-GD2 treatment for disposal of assets, and agree that there is not a strong rationale to move to an approach whereby disposals of fully depreciated assets are treated as 100% fast money.

FQ32. Do you agree with the proposal for the ex ante base revenue definition we will use to calculate the re-opener materiality thresholds?

We agree, but only in part.

Ofgem has set out that where uncertainty mechanism (UM) materiality thresholds are sized as a percentage of average annual ex ante Base Revenue (where the default materiality threshold is 0.5%), average ex ante base revenue is calculated as follows:

- The Totex used to calculate ex ante base revenue is the same as that used in the BPI calculation, i.e. it excludes ongoing efficiency adjustments, UMs that are capitalised under Bucket 2 capitalisation rates (reopeners and UIOLIs), and additional allowances for real price effects.
- This Totex is then used to derive calculated revenues in the BPFM, and a subset comprising fast money, pass-through, depreciation and return is taken as base revenue.
- A simple average of this ex ante Base Revenue is calculated over the RIIO-3 period.

We agree that there is a benefit to setting the monetary values for UM materiality thresholds in advance of the price control, for transparency and simplicity.

However, we have reservations regarding some elements of the suggested approach, in particular (a) the exclusion of OE adjustments – which are foreseeable at the start of the price control so the rationale to exclude them is not clear, and (b) the transparency of the calculation, given that the published BPFM presents Totex after the OE adjustment, inclusive of RPEs, with some uncertainty mechanisms included.

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?

Yes, we agree.

For RIIO-GD3, Ofgem has proposed to present all ODI caps and collars as a percentage of RoRE, rather than a percentage of Base Revenue. Ofgem's rationale, as set out at SSMC, is that RoRE is more directly relevant to investors, RAV will generally be more stable than revenue, and that rewards and penalties will be '*sized*' according to notional gearing.

To enact this decision, Ofgem proposes to use an ex ante calculation of the equity portion of RAV to calculate the monetary value of ODI caps and collars, and then take a simple average over the RIIO-GD3 period to set the caps and collars for the duration of the price control. Ofgem will use total Totex allowances for this calculation, i.e. including all UMs, and after ongoing efficiency and real price effects adjustments. Ofgem's rationale for using the full Totex allowance is that incentives are intended to reward companies' actions across the whole of the price control, unlike the BPI calculation, where the reward or penalty is sized around costs that were foreseeable at the outset of the price control.

We agree that setting ODI caps and collars in RoRE terms helps to simplify and clarify the size of incentives, and we agree with Ofgem's proposed approach for implementation.

FQ34. Do you agree with the proposal to move to using nominal WACC as the single uniform TVOM?

We understand Ofgem's motivation to move towards using the nominal WACC as a single time value of money (TVOM) rate, and agree that using a single TVOM would help simplify the financial modelling.

FQ35. Do you agree with the proposed base revenue forecasting penalty mechanism?

We do not agree with Ofgem's proposal to introduce a Base Revenue Forecasting Penalty (BRFP) in the proposed form.

In our view, the introduction of this penalty has the potential to penalise GDNs for forecasting errors driven by factors that could not have been foreseen, and therefore could not have been built into forecasts, no matter how sophisticated. This could result in arbitrary and unfair penalties.

This issue is particularly driven by pass-through costs. Base revenue is made up of four components: fast money, depreciation, return and pass-through costs. Pass-through costs, in turn, are made up of a number of costs, with the most material ones being shrinkage costs, NTS exit costs, prescribed rates and other miscellaneous pass-through costs that can vary materially in size from year to year and across GDNs. Many of these costs are highly volatile (not just from year-to-year, but within years), sensitive to short-term shocks, and as a result are very difficult to forecast accurately. Shrinkage costs, for example, are calculated on the basis of the prevailing gas price, which can be highly unpredictable as demonstrated by sudden spikes and volatility caused by the war in Ukraine. Pass-through costs represent a significant proportion of Base Revenue – averaging around 23% in RIIO-GD2 – with the absolute value expected to increase in RIIO-GD3 for NGN.

We also note that UNC modification proposal 0903, '*The Introduction of a Single NTS Capacity Reference Price*', is likely to exacerbate the issues discussed above. For context, NTS Entry tariffs have been found to be higher and more sensitive to volatility in comparison to historical averages and Exit tariffs. Modification 0903 proposes to introduce a single capacity tariff across all Entry Points and all Exit Points, with the aim of reducing tariff volatility for gas consumers. However, the implication of this is that exit costs paid by GDNs are expected to increase by around 50% with a yet to be tested impact on volatility. This will increase the scale of the NTS exit costs we pay, and consequently, the magnitude of forecasting errors driven by unforeseeable factors that drive the costs of the NTS.

Ofgem notes that it has recently introduced a BRFP in RIIO-ED2, and that it thinks there is value in having consistency between sectors where possible.[1] However, this is not a legitimate reason to introduce a new regulatory mechanism. The context in the ED sector is likely to be different, and forecasting of Base Revenues may be less challenging – for example, gas prices are not a material driver of Base Revenues in ED. The benefit of consistency across sectors is not clear – rather than simplifying regulation, "*consistency*" in this case involves introducing a new mechanism, which adds complexity and risk.

Ofgem acknowledges in the DD 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*"[2]. It therefore proposes to waive some or all of the penalty if the error is caused by factors outside the reasonable control of the licensee. However, in our view, this is not a sufficient or appropriate solution to the issues underlying this incentive. The waiver process will create unnecessary complexity and resource burden for both Ofgem and companies. It will also inevitably rely on Ofgem's subjective judgement, creating regulatory uncertainty.

Ofgem also argues that the penalty threshold (proposed to be set at 8% of Base Revenue for the GD sector) will provide headroom and comfort that the penalty will not be triggered routinely. While it is true that a larger threshold will reduce the frequency of penalties, a large threshold does not address the issue of penalties being driven by forecasting errors that could not have been avoided. In fact, errors driven by unforeseeable external shocks (such as the impact of the Ukraine war on gas prices) are precisely the types of errors that are likely to be large and therefore trigger penalties.

Given these concerns, our view is that Ofgem should not introduce the BRFP, or if it does introduce the BRFP, to exclude pass-through costs as a minimum.

FQ36. Do you agree that the thresholds have been set appropriately?

We recognise that Ofgem has increased its proposed threshold for GD from 6% to 8% of Base Revenue. As explained in FQ35, while this helps reduce the frequency of unfair penalties, it does not address the underlying issues with the incentive. In our view, the more appropriate course of action is not to introduce this incentive altogether, or to exclude pass-through costs from the calculation of the penalty. Short of these solutions, our view is that the threshold should be increased to 10% of Base Revenue as a minimum, to further reduce the risk of unfair penalties.

[1] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 11.99.

[2] Ofgem (2025), RIIO-3 DD Finance Annex, paragraph 11.98.