



SGN Draft Determination response overview

August 2025



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Foreword by Simon Kilonback, CEO, SGN

Our GD3 Business Plan set out the £4.5 billion investment programme we need, as duty holder, to operate a safe and reliable gas network and maintain security of supply for our six million domestic and business customers across south London, the south of England and Scotland. The Draft Determination removed £1 billion from our GD3 allowances. This represents a £1 in £4 cut – or £200m per year – to essential, safety-driven asset investment.

Our investment programme focuses only on what we must deliver to continue operating at the same level of integrity as we do today. It is untenable for a quarter of our investment plan to be disallowed, whilst being expected to maintain appropriate standards of safety and service, and long-term financial stability. Under no circumstances can we support a reduction in the asset integrity of our network. Investment is essential to ensure we meet our licence obligations as an operator of public infrastructure that poses a significant safety risk and disruption when it fails. For example, our investment to improve the safety of gas supplies to high-rise buildings is essential to keep the gas flowing for some of the most vulnerable people in society.

As a highly experienced leader with a track record of successful delivery across multiple infrastructure classes in both the public and private sectors, I understand the pressures of delivering investment whilst keeping costs affordable for customers. Our Business Plan protects our customers' interests by balancing affordability with essential investment required to maintain safe, secure and resilient infrastructure.

We must learn the lessons from the Cunliffe Review and recognise the limitations of econometric modelling. We have experienced the impact of economic theory not matching the reality of the market in which we operate. In our Southern network, in the first years of GD2, more than a third of our mains replacement contractor teams moved to other industries due to allowances that were set below a competitive market rate.

Our GD2 plan accurately forecasted the costs of delivering our mains replacement programme, which were disallowed. As the workload is part of the HSE mandated programme, our investors underwrote the measures necessary to undo the damage of underfunding and rebuild delivery. In GD3, the unprecedented competition for a finite pool of supply chain resources will only intensify with increased infrastructure investment in the UK. We therefore need the real world cost of operating in the South to be recognised.

Our final settlement must be grounded in reality, not theory. It is unrealistic to expect that gas networks should be able to outperform the rest of the UK economy with productivity improvements of 1% every year after decades of efficiency-targeted regulation. Decarbonisation is taking place more slowly than the NESO scenarios and GDNs will have an active role to play after 2050. In the Draft Determination, significant cuts to workload outside the HSE mandated Iron Mains Risk Reduction Programme (IMRRP) have been made. Cutting workload in this way is not consistent with prudent, industry standard asset management practices required to provide security and resilience of supply for peak demand.

We urge the regulator to undertake four key actions; (i) restore all critical safety workload, (ii) correct the suite of errors in Repex unit costs, (iii) correct allowances to reflect operational reality, and (iv) address manifest inconsistencies in the risk and return package.

Only by taking these four actions to restore the necessary workload, cost allowances, and financeability will long-term investability be maintained.

As the CEO of a safety-critical business, I cannot accept a regulatory settlement that does not enable the safe operation of our networks or represent an investible proposition. We have the solutions identified, and by introducing our proposed adjustment for accelerated depreciation, we can restore the £1 billion safety-critical investment and maintain our financeability, whilst increasing bills by less than £1 per year.

My team and I remain committed to working with Ofgem to resolve these issues through a collaborative programme of activity that will enable us to secure an investable and deliverable Final Determination.



Simon Kilonback
CEO, SGN

Section 1 Executive summary

1.1 Introduction

- 1 In December 2024, we submitted our RIIO-GD3 Business Plan. We set out an efficient £4.5bn programme of investment that prioritised the operation of a safe and reliable gas network, set in the context of Great Britain's transition to net zero. Our plan reflected our customers' and stakeholders' priorities and delivered improved outcomes for those supplied by our networks in Scotland and Southern England.
- 2 In its Draft Determination of our plan there are areas where Ofgem has engaged with the evidence we provided and reflected our customers' and stakeholders' expectations of our service. This includes:
 - recognising the unique role of gas networks in accessing and directing support to our most vulnerable customers by providing £45m of dedicated funding for vulnerable customers across both our networks, enabling us to continue working closely with our trusted community partners to help customers use gas safely and efficiently and access targeted financial support;
 - continuing to focus on reducing methane emissions through £12.4m of investment in advanced leakage detection and £11.22m for the continued deployment of innovative technologies such as remote pressure management, and recognising the potential and opportunity to pursue intelligent gas grid and SIU decarbonisation through the NZASP reopener; and
 - providing £26.8m of dedicated funding to advance our data and digitalisation capabilities and [REDACTED] for ongoing investment in cyber security to protect our customers and our network.
- 3 However, the overall Draft Determination package does not provide the allowances required to operate our gas networks safely and resiliently, and we must be allowed to make the £4.6bn¹ of essential investment required in the GD3 period. If investment is cut below this level, the consequence will be a less safe network, more repairs, longer interruptions, deteriorating standards of service and higher bills over the longer-term as work is deferred and risks increase. This would not be an acceptable outcome for our networks, our customers, or the regulator.
- 4 We have responded to Ofgem's feedback, providing additional information and evidence to support our Business Plan. Our ask is clear; to maintain a safe, resilient and investable network, four actions need to be implemented ahead of the Final Determination: These are:
 - (a) Action 1 – Restore all safety-critical workload;
 - (b) Action 2 – Correct the suite of errors in Repex unit costs;
 - (c) Action 3 – Correct allowances to reflect operational reality; and
 - (d) Action 4 – Address manifest inconsistencies in the risk and return package.
- 5 By taking these actions Ofgem can deliver a price control that maintains a safe and reliable network and the high standards our customers expect, ensuring both the safe operation and responsible financing of our network, with an appropriate balance of risk.
- 6 We recognise that in a low-carbon energy system the gas networks will play a different role than they do today. Current evidence shows customer connections are increasing² and alternative heating deployment remains significantly below government targets³. However, we were required to submit Business Plans against NESO scenarios⁴ that assume the gas networks will have little or no role beyond 2050. The current pace of decarbonisation is slower than these scenarios assume, and yet the Draft Determination has reduced the payback period for investment from 16 years to 11 years⁵. This will increasingly constrain networks into making sub-optimal decisions that increase the overall cost to the consumer. This is not consistent with prudent, industry standard asset management practices required to provide security and resilience of supply for peak demand and is symptomatic of a Draft Determination that has focussed on theory rather than basing decisions on evidence of

¹ There is £140m increase in investment that reflects the Draft Determination's Employers NI increase, inclusion of Tier 2a and the inclusion of South London MP mains project, Advance Leakage Detection and Biomethane roll our baseline allowances.

² Customer numbers have increased by 14,000 since the start of GD2, SGN RRP Submission July 2025, sheet reference 9.03.

³ Heat Pump Deployment Statistics: March 2025 - Government supported heat pump installations for the last year was 45,076 against a government target of 600,000 by 2028, of which only 14,600 were existing gas customers.

⁴ Holistic Transition pathway utilised in Ofgem Business Planning Guidance and restated in FES 2025 Data Workbook.

(<https://www.neso.energy/publications/future-energy-scenarios-fes/fes-documents>)

⁵ RIIO-3 Draft Determinations - Gas Distribution, July 2025, para 3.69, pg29

customer uptake of alternative heating options. We disagree with this approach⁶. Using hypothetical scenarios to drive a 'fix on fail' approach to investment in critical infrastructure poses an unacceptable safety risk and does not achieve the stated effect of benefitting consumers.

- 7 The focus on theoretical scenarios undermines incentives to invest in innovative projects that reduce methane emissions and support decarbonisation. It also locks consumers into a higher cost decarbonisation pathway that is unlikely to be realised and limits economic potential of alternative net-zero pathways that may be more cost effective or more deliverable.
- 8 In this Executive Summary we summarise the four actions required and explain the impact of failing to act. The subsequent sections cover each action in more detail and present additional data and analysis, including additional evidence from independent experts that supports our response, set out in Section 6: Supporting Evidence.

1.2 Actions to be taken before the Final Determination

- 9 For the Final Determination to set the basis of a five-year price control period in which customers receive safe and secure gas supplies and investors have a 'fair bet'⁷ at achieving the proposed returns, four fundamental actions need to be taken. These are our priorities to ensure that we can maintain a safe and secure network and deliver the outcomes expected by customers and set by Ofgem in its GD3 methodology⁸. Taking these actions reduces the likelihood of errors remaining in the Final Determination.

(a) Action 1: Restore all safety-critical workload

The rate of deterioration of assets outside the mandatory replacement programmes is increasing faster than the rate of replacement. This heightens the risk to the public, the risk of a breach of licence obligations and causes more methane emissions from our network. This will undermine the improvements we have delivered over the last 10 years and places an unacceptable burden on future customers as they become exposed to greater risks and higher costs of mitigating them. Managed decline is not an option for safety-critical gas infrastructure. All safety-critical workload must be restored in the Final Determination.

(b) Action 2: Correct the suite of errors in Repex unit costs:

- 2a: Address the gap to market costs in Repex allowances – there is a clearly identifiable gap between the allowances provided for in the Draft Determination to deliver our mandatory Tier 1 Repex workload and the market rates required in the south of England to efficiently deliver it. This gap was demonstrated in GD2 when 35% of the contractor market left to work in other sectors where they could earn more. If allowances are not adjusted appropriately, we risk losing the operational gains we have made, and the gap will continue to grow in GD3 as competition intensifies further. This will be to the detriment of our customers in the south. We have proposed two adjustments to close this gap in the Final Determination, (i) recognising the regional difference between unavoidable contractor labour rates by introducing a regional contractor premium of 6% above the current recognised direct labour regional premium and (ii) recognising that complexity has a high regional aspect that impacts productivity in the south of England and introduce a suitable proxy for Repex complexity.
- 2b: Recognise the changing requirement to maintain safety in multiple occupancy buildings (MOBs) – the introduction of the Building Safety Act 2022⁹ and the publication of the final report of the Grenfell Inquiry¹⁰ have introduced significant changes in the way in which gas should be transported into MOBs. In GD3 this is driving a higher volume of work but there is significant uncertainty in the cost of completion. At present, the cost drivers for determining an efficient cost are poorly represented in the cost assessment methodology, therefore we propose that the HSE reopener mechanism is adjusted to fund project delivery on an incremental two-year basis. This will enable improved clarity on the safety expectations of recent legislation, improved alignment with the RESP and local authorities' objectives, and improved data collation.

⁶ SGN Business Plan main document, page 38, section 5.1.1.

⁷ In UK utility regulation, a "fair bet" is the idea that when companies invest in infrastructure under a regulated regime, they should expect to earn a return that fairly reflects the risks they take — neither excessive nor insufficient — over the life of the investment.

⁸ RIIO-3 Sector Specific Methodology Decision – overview document; 18 July 2024, page 7.

⁹ [Building Safety Act 2022](#)

¹⁰ [GRENFELL TOWER INQUIRY: Volume 1](#)

- 2c: Recognition of efficiently forecast Business Plans – we have identified two errors in the cost assessment process which are resulting in some networks appearing more efficient than they should be, due to material distortions between the forecasts provided and actual delivery. These distortions create an embedded inefficiency that is not picked up through the econometric cost assessment process and must be corrected. The corrections required are to normalise the assumptions between networks for (i) the forecast lay to decommissioning banding mix and (ii) the forecast abandonment ratio.

(c) Action 3: Correct allowances to reflect operational reality:

- 3a: Apply an appropriate driver to determine repair efficiency – The driver for repair costs is currently the number of external condition reports that are called into the gas emergency number. This assumes that external condition reports are independent of company activity and directly linked to the number of repairs undertaken. However, this assumption is wrong. While all repair teams on the ground will sweep to identify additional leaks in the vicinity of the original report, some will include any additional repairs in the same report while others will make multiple reports, distorting the repair to report ratio. This means that the cost driver used to determine efficient repair costs is being influenced by company policy (an endogenous factor). We agree with Ofgem that it is important that repair funding is determined by factors that cannot be easily influenced by companies (exogenous factors). We therefore propose that ‘km of metallic main’, which is a robust exogenous driver with strong engineering justification, should be adopted to avoid internal policies distorting funding.
- 3b: Recognise appropriate costs associated with regional workload and streetwork costs – the appropriate costs of working in each region must be appropriately determined ahead of comparative analysis. Ofgem must ensure that the existing calculations are appropriate and work as intended. Specifically, these are to (i) recognise the geographical difference in workload mix used in the composite scale variable and end the distortion of applying a single average workload mix to all networks, and (ii) capture an accurate reflection of actual streetwork costs rather than the proposed 10 year average, which directly penalises those networks operating in areas with councils that are rapidly escalating their revenue by raising streetwork charges.
- 3c: Reflect an appropriate ongoing efficiency requirement – since 2008, total factor growth (gross output) productivity in the UK has struggled to be positive, and it is not reasonable to assume that utilities can outperform the rest of the economy when it comes to sustained productivity improvements. Ofgem need to align the ongoing efficiency expectations of gas networks with the rest of the economy. As we suggested in our Business Plan 0.5% is an ambitious adjustment. This is a view shared by all GDNs.

(d) Action 4: Address manifest inconsistencies in the risk and return package:

- 4a: Providing an appropriate allowed return on capital - the return on capital set out in the Draft Determination is insufficient to reflect the costs of raising capital and provide an appropriate return to investors in the RIIO-GD3 period, given the risk exposures and the longer-term uncertainties associated with investment in the gas transportation sector that are yet to be resolved. This needs to be corrected by (i) increasing the cost of debt allowance by 45bps to 5.52%, (ii) an assumed dividend yield in excess of 6% reflecting a business with no prospect of any material RAV growth in the future and (iii) implementing a cost of equity 80bps higher to 6.84%, reflecting corrections to methodological weaknesses, reflecting current market conditions and having a smaller beta range that dismisses the bottom end of Ofgem’s range as not reflecting forward looking gas risk.
- 4b: Providing a package with an appropriate balance of risk to enable an efficient SGN licensee to achieve that allowed return. Taking the draft determination at face value and adjusting for known errors, this would provide a negative base case exposure of [REDACTED] in return on regulated equity (RoRE) for the notional GDN in the GD3 period. For a notional company operating in the southern region the base case risk exposure is higher at [REDACTED]¹¹. Since the draft determination has been published, there has been good communication with Ofgem’s engineering team, which leads us to believe the workload will be reinstated. This would reduce our downside risk exposure to [REDACTED] for the notional GDN and [REDACTED] for a notional company operating in our southern region. Therefore, a notional company operating in SGN’s southern footprint can only expect to earn [REDACTED] proposed cost of equity. If long-term cost recovery risks are taken into consideration, the notional GDN has an additional [REDACTED] exposure.

¹¹ SGN-GD3-DD-ECR-10 - KPMG RIIO GD3 Draft Determinations – Risk analysis for a notional GDN August 2025 (submitted with this response)

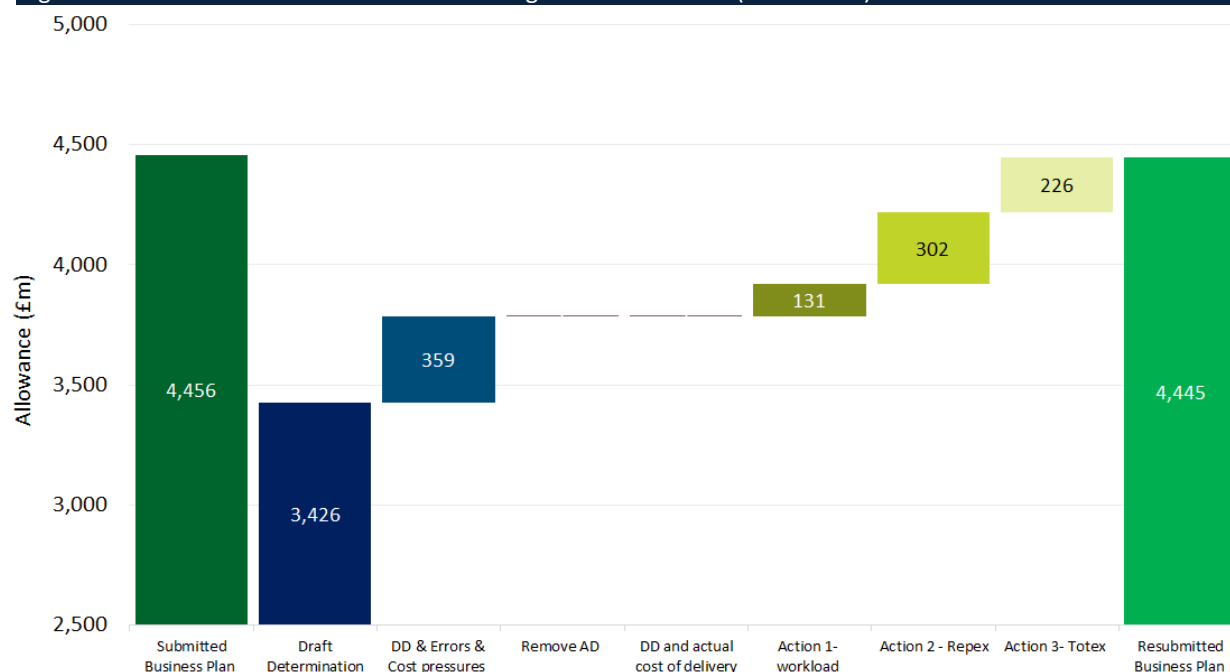
These results are markedly different from Ofgem's 'light touch' approach to a balanced assessment, which assumes neutral performance across all areas and fails to examine finance risks at all, including the risk of not recovering efficiently incurred financing costs. The magnitude of these RORE risks signals an investability issue that needs to be addressed in this price control with credible and urgent measures to deal with both the short-term Totex and cost of debt risks at source and the longer-term cost recovery risks, which together signal a shift in the sector risk profile

- 10 Restoring safety-critical workload and correcting errors and allowances will cost customers an extra 90p per year.¹² enabling the safety-critical investment for our customers and mitigating some of the key risks that our investors are otherwise exposed to. This is explained further in the following section.

1.3 Impact of failing to act before the Final Determination

- 11 Failing to act will significantly undermine our ability to operate our network safely and result in an inappropriate balance of risk. All workloads must be allocated an appropriate unit cost to ensure they are efficiently deliverable and do not compromise the resilience of supplies, high-quality service and environmental improvements, while also maintaining the long-term investment in skills and training necessary to sustainably support the delivery of critical infrastructure.
- 12 Figure 1, below, shows the respective steps and the actions required to bring the Final Determination back to a well-calibrated, sustainable, long-term package and the resulting impacts on allowances.

Figure 1: Trace from Draft Determination through to resubmission (allowances)



Source: SGN analysis of the Draft Determination.¹³

- 13 This shows the impact on allowances of moving from the original Business Plan of £4,456m, to the plan published in the Draft Determination, which cut allowances by more than £1bn to £3,426m. It then sets out the adjustments¹⁴ and actions required to reach our resubmitted Business Plan of £4,445m. These are:

¹² This reflects the difference between the Draft Determination with technical errors corrected and additional workload identified in the Draft Determination added, with accelerated depreciation for new assets is removed and replaced with a trigger mechanism. Maintaining accelerated depreciation on new assets increases the cost to customer by £8.70/year.

¹³ Please note that the Business Plan submission value of £4,456m this differs to the £4,545 set out in the Draft Determination due to a mismatch in the treatment of ongoing efficiency.

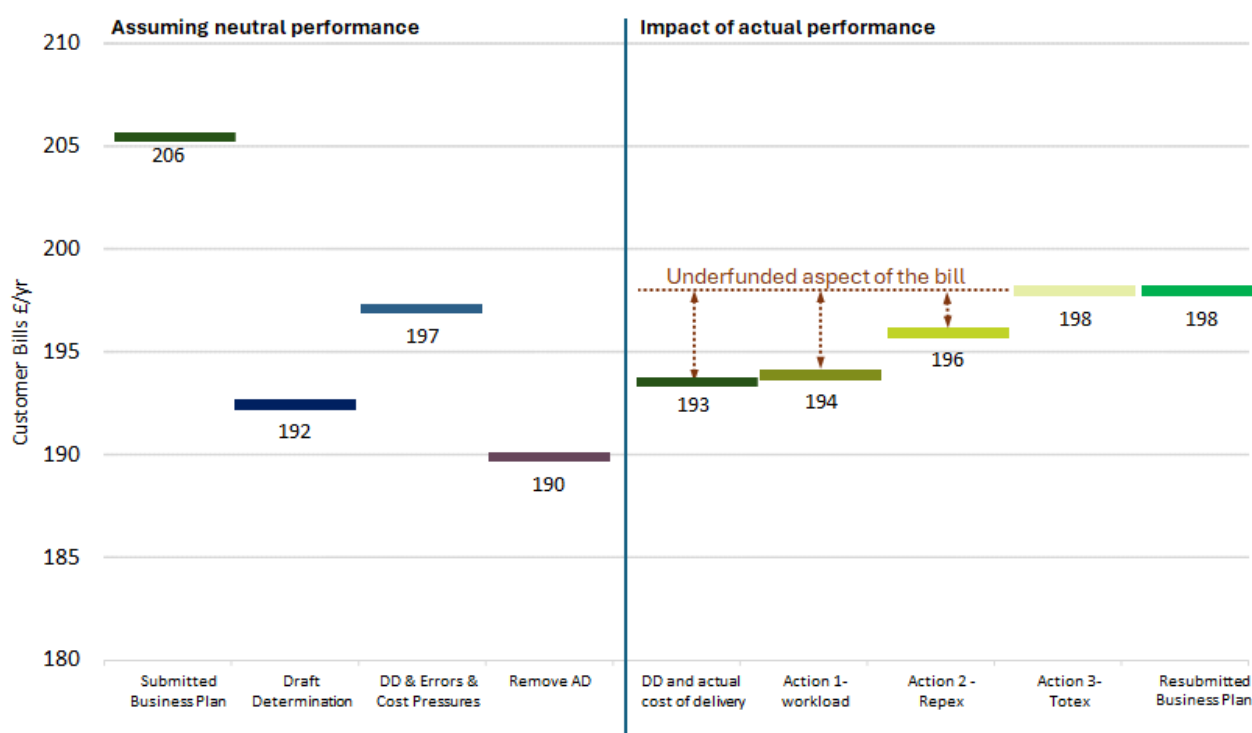
¹⁴ It should be noted that some adjustments do not have an allowance impact. For example, the removal of accelerated depreciation reduces bills from £194 to £187, mitigating the bill impact, but does not change Totex investment. It should also be noted that the credit rating impact (measured as AICR) represents the average for GD3 and does not include the risk profile set out above.

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- a set of technical updates post Draft Determination including the correction of errors¹⁵ that have been identified and subsequently accepted by Ofgem in the cost benchmarking methodology and additional investments that have been added to Totex in the Draft Determination (such as Tier 2a, South London Medium Pressure Mains etc), which increase allowances by £359m;
- removal of accelerated depreciation on new assets as proposed in the Draft Determination, and instead introducing a trigger mechanism for accelerated depreciation – this does not impact allowances but does impact bills (see figure below);
- delivering our safety-related workload in an unfunded manner at Draft Determination unit rates - this does not impact allowances but does impact bills (see figure below);
- The allowance impact is then built up through the actions set out above;
 - (i) Action 1 - the impact of restoring safety workload, which increases investment by £131m;
 - (ii) Action 2 – correcting the suite of Repex errors so allowances accurately represent the cost of completing the required workload, which increases allowances by £302m; and
 - (iii) Action 3 – correcting allowances to reflect operational reality, which increases allowances for delivering non-Repex workload by £226m.

14 Figure 2 presents the impact that these actions and adjustments have on customer bills. The graph is presented in two halves. The first holds the assumption of neutral performance (i.e., we are able to deliver the workload and costs set out in the Draft Determination), the second removes that assumption, and allows the additional cost overspend to be shared through the Totex incentive mechanism, drawing out components of the bill that are funded and remains unfunded.

Figure 2: Bill impacts of adjustments and actions



Source: SGN analysis of Draft Determination

15 This graph shows that the Draft Determination reduced bills by £14 to £192 per household per year. However, this comes at the expense of safety-critical workload and the necessary allowances to efficiently deliver the work required. Our resubmitted Business Plan, which restores all workload and provides an appropriate level of

¹⁵ At the time of writing (15/08) 136 errors had been posted on Gitlab, 120 had been closed, and approximately half of those closed errors were accepted by Ofgem.

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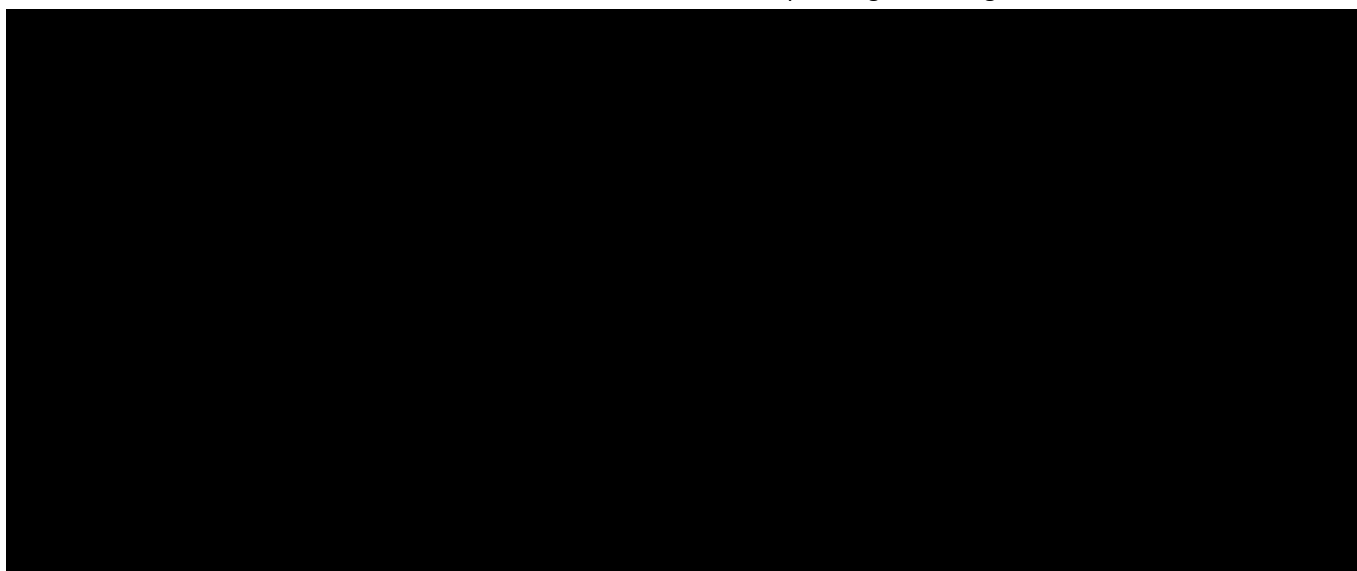
funding, will cost customers an extra £1 per year (compared to the corrected Draft Determination), resulting in an annual bill of £198. The change to bills is explained by:

- the correction of the accepted errors and additional Totex adding £5 per year;
- the replacement of accelerated depreciation with a trigger mechanism, as set out in our business plan, (and is not expected to be triggered in GD3) reduces bills by £7 per year;
- applying the anticipated outcome of both workload and cost will lead to an over-expenditure that will go through the Totex sharing mechanism, and this will increase consumer bills by £3 per year. However there remains £5 per customer that is unrecovered (the difference between £198/y and £193/yr) and borne by investors and is reflected in the balance of risk set out below.
- This is then recovered through:
 - (i) Action 1 - restore all safety workload, adding £1 per year;
 - (ii) Action 2 – correct the suite of Totex errors, adding £2 per year; and
 - (iii) Action 3 - correct allowances to reflect operational reality, adding £2 per year to bills. Taking this final action brings customer bills to 198 per year, aligned with our resubmission.

16 If you assume the Draft Determination is deliverable for both workloads and costs, then this would deliver broadly acceptable credit metric ranges for a notional company. In actuality, workload removed in the Draft Determination reflects the reality of delivering to uphold safety standards at market rates, but without funding being provided through allowances. [REDACTED]

17 By not implementing accelerated depreciation through the trigger mechanism, we are able to save £7 per year on the bill, allowing an extra £1bn of investment to be delivered with only a 90p per year increase in the bill per customer from the updated draft determination position, equivalent to a pint of milk¹⁶.

18 Figure 3, below, compares the expected equity returns (RoRE) range for risk exposure for Scotland and Southern Networks stepping through from the Draft Determination to our proposals as set out in this response. The figure shows the impact on a notional company operating in both the Scotland and the Southern licence areas, showing the best and worst case under the draft determination. We then step through the mitigations set out above.



Source: SGN-GD3-DD-ECR-10. GD3 Draft Determinations risk analysis for SGN, KPMG, Aug 2025

19 Looking at RIIO-GD3 risks¹⁷, Figure 3 shows that the Draft Determination, with the known errors identified and the risk associated with workload, allowances and financing, results in a RoRE risk range significantly below Ofgem's assessment of a neutral mid-point [REDACTED]¹⁸. This understatement by Ofgem is driven by their lack of a full impact assessment (which assumes a simple +/- 10%

¹⁶ [British Whole Milk 3.7% Fat | ALDI UK](#) (referenced on 24th Aug 2025)

¹⁷ The figures presented here are on a comparable basis to the assessment in the draft determination. It does not take into account long-term risk that are set out in KPMG's analysis and would increase the downside risk by a further 174bps.

¹⁸ RIIO-3 Draft Determinations – Finance Annex, July 2025, Figure 4

Totex performance and no assessment of financing risk) and, as a result, does not reflect the risk arising to the notional company.

- 20 Undertaking Action 1 (set out above) is equivalent to the 'workload addback' adjustments in Figure 1 above. Actions 2 and 3 are equivalent to the 'no cost' gap risk adjustment, and the 'recalibration of cost of debt & ODIs' is capturing the financing risk adjustments set out in Action 4.
- 21 This analysis also demonstrates the materially greater risk exposure of a notional company operating in our Southern Network. If these risks remain unmitigated, then there is a significant risk that the notional company operating in the Scotland and Southern licence areas would not have a reasonable expectation of delivering their safety obligations to the HSE, the outputs set out in the licence, achieving customer and environmental outputs in Scotland and Southern [REDACTED]. All of which are necessary to attract long-term, high-quality investors.
- 22 The Final Determination should mitigate these risks at source. If they can't be mitigated at source, then appropriate protections must be provided through aiming up the cost of equity to recognise the increased risk exposure and through a re-calibration of the Revenue Adjustment Mechanism (RAMs) to protect investors from the risk of under-performance and protect consumers from the risk of out-performance, (this is set out in more detail in our response to FQ27).

1.4 Impact of failing to act on investability

- 23 The Draft Determination impacts the financial standing of gas networks in this price control period and beyond. Sustainably funding investment in our network will require us to refinance current debt and retain equity for many years to come. The risk analysis set out above suggests that an investor would not reasonably expect to earn the allowed return on equity and the Draft Determination would not be considered a 'fair bet' [REDACTED]
- 24 The Draft Determination significantly understates the unique gas risks we are facing and assumes there is no difference in underlying sector risk profiles between electricity and gas. Evidence shows the cost of new debt allowances varies across sectors, reflecting the higher credit risk priced in by the market for gas. All other things being equal, this difference needs to carry through to higher cost of equity estimates to ensure they remain appropriately risk reflective and therefore investable.
- 25 Shareholder returns come in the form of dividends and RAV/capital growth. If the RAV is not expected to grow materially, as was assumed in the Draft Determination, the only return equity investors will receive is from dividends. If notional company financeability assessments are to be credible, the assumptions need to reflect this real-world position. This means that the dividend stream investors receive (excluding accelerated return of capital) in the notional company must be closely aligned with the appropriate cost of equity of the notional company which is proposed at 6.84%. [REDACTED]
- 26 There is a longer-term and more fundamental risk that GDN's will not be able to recover all their ongoing costs and RAV due to a lack of appropriate regulatory structure to recover these costs in an affordable way. Whilst DESNZ has identified the need to review this, this has not been remedied.¹⁹ The consequence of these risks, together with the Totex risks identified above, is that the Draft Determination of the GD3 price control does not represent a fair and balanced risk for our investors, and capital markets are reflecting this. We need the Final Determination to make a clear statement that investors in the gas network should always be able to rely upon the recovery of efficient expenditure independent of the future of gas scenarios. This commitment must have been implicit in Ofgem's conclusion that the gas networks are financeable, and this needs to be explicitly stated.
- 27 It is important to recognise that the proposal to address this through accelerated depreciation does not deliver the mitigation of the material cost recovery risk, its stated objective. The Draft Determination proposal of implementing accelerated depreciation on new assets in GD3 will add £8.70 per year to customer bills for little benefit and could have a further negative impact on investor perceptions. We therefore consider Ofgem's current

¹⁹ Midstream Gas System: Update to the market, June 2025. "However, the government recognises the importance of clarity and stability, and therefore aim to decide on policy to inform investment recovery prior to the commencement of RIIO-4" (emphasis added).

approach to accelerated depreciation is not warranted or proportionate and suggest that a trigger mechanism based on real-world customer disconnection activity, of the type we proposed within our submitted Business Plan, should be introduced together with potential robust long-term cost recovery mechanisms.

- 28 In the following sections, we run through the four actions set out above to give a description of the error, a summary of the evidence setting out why a change is required and an appropriate remedy.

Section 2 Restore all safety-critical workload

- 29 The gas network does not ‘fail-safe’. A failure of the network leads to a potentially dangerous release of gas, which, if it accumulates in a building, causes a threat to life. It is essential, therefore, that the Final Determination includes the cost of all our safety-critical workload.
- 30 The Draft Determination appears to set an investment threshold based on established and immediate safety requirements but does not proactively address known risks in the network. This approach is moving towards a model of “fix on fail”, which is not appropriate because if networks know about a risk, fail to act on it, and as a result an asset fails with a material consequence, companies would be held at fault by the HSE and public confidence in the sector and its regulation would be threatened.
- 31 Running the gas network on a reactive basis of investment will undermine its safety. This is unacceptable for our customers, management team and investors. We welcome that Ofgem has been clear where we need to provide more information and have clarified that it is willing to restore workload as we produce further evidence.
- 32 It is essential that this safety-critical workload is restored, and it is also essential that it is funded appropriately. It is untenable to operate a safe and reliable network with allowances that do not cover the cost of completing necessary work in the regions in which we operate. In this section, we present Action 1 – restoring the five major categories of work that have been removed, these are:
- (a) Bulk services;
 - (b) MOBs;
 - (c) Legacy safety disconnections;
 - (d) Rejected Investment Decision Packs (IDPs); and
 - (e) Non-Tier 1 Repex workload.
- 33 We consider each of the five major categories of work that must be restored in the Final Determination, in turn below.

2.1 Bulk services²⁰

- 34 The bulk services programme²¹ replaces steel tails (services), assets created between 1970 and 1990, which run from the end of polyethylene pipes into buildings. This programme began in GD2, with 5,250 steel tail replacements, enabling us to set out the processes, procedures and workforce to carry out the work. Now the programme is established, we propose to double our workload to 10,500 in GD3. Ultimately, the programme will see us replace 500,000 steel tails by 2050. We anticipate significantly accelerating the programme from GD4 when the Tier 1 iron mains replacement programme concludes and its workforce becomes available to deliver the higher workload.
- 35 Over GD2, corrosion and degradation of existing steel services have been identified across the industry as an increasing source of risk of gas in building events. Two significant incidents²², thankfully, neither of which was fatal, has been attributed to steel tail failures in GD2 and a programme of work is required to mitigate this risk. As set out in our response to SGNQ16, the programme of 10,500 service replacements needs to be restored as the HSE has confirmed that they require us to continue this programme²³. For further engineering justification please refer to document #SGN-GD3-DD-ENG-SD015.

2.2 Multiple occupancy buildings²⁴

- 36 We included a £248m programme to improve the safety of MOBs within our Business Plan²⁵. This included the refurbishment or replacement of 6,336 steel risers, the pipes that supply gas to different floors of the building, because the rate of deterioration of these assets is increasing. The remaining workload is being driven by new

²⁰ RIIO-3 Draft Determinations – SGN, July 2025, Appendix 1, pg 58

²¹ SGN-GD3-EJP-RPX-001, Dec 2024

²² Whale Island Way, Portsmouth (2021) and Gorse Park, Ayrshire (2022)

²³ Reply to J Deveney letter of 22 July 2025

²⁴ RIIO-3 Draft Determinations – SGN, July 2025, Appendix 1, pg 55

²⁵ SGN-GD3-BP-00, Dec 2024, pg3

health and safety legislation introduced following the Grenfell Tower tragedy. Apart from Pipeline Isolation Valves (PIV) replacement, all the MOB's workload was disallowed.

- 37 We have provided the data asset repository²⁶ as requested in the Draft Determination, and further data in our response to question SGNQ16. This data will assist Ofgem in validating the workloads proposed in our plan and the risk prioritisation that we have applied to establish the next phase of our continuing intervention programme which extends beyond GD3. It will also demonstrate the safety imperative of replacing, remediating, or repairing these assets based upon the condition and risk information provided. More details on the cost of MOB workload are provided in section 3.2 below, and we require that the full workload be restored and appropriately funded. For further engineering justification, please refer to document #SGN-GD3-DD-ENG-SD004.

2.3 Legacy safety disconnections²⁷

- 38 There is a programme of work where disconnections historically undertaken by capping a supply at the Emergency Control Valve (ECV) have been deemed an unacceptable risk by the HSE, and we need to return to the site and disconnect at the point that the service leaves the main. The HSE's position on this has been clarified in recent years and there has been a cross-industry working group to establish whether innovative solutions could successfully manage the risk. The innovation has so far resulted in a satisfactory outcome and as a result, we now need to progress this workload. As set out in our response to GDQ22, capping off at the ECV was standard, HSE-accepted practice, and disconnection at the main was never funded for in previous price controls. We require legacy safety disconnections to be implemented as volume driver.

2.4 Rejected Investment Decision Packs

- 39 Ofgem has disallowed Investment Decision Packs (IDPs) in a number of areas. These investment proposals include 'Steel Services operating above 75mb'²⁸, 'Local Gas Treatment'²⁹, 'Functional Safety'³⁰, 'Network Integrity'³¹ and 'Cams Hall'³². We have submitted additional information on each IDP, which is provided in response to SGNQ16. This will enable Ofgem to validate our proposed workloads, verify the prioritisation approach we have taken, understand the health of the specific assets concerned and understand the way we have developed our programmes of work. Each of these projects needs to be restored for the safety and resilience of supply reasons provided within the respective engineering pack.

2.5 Non-Tier 1 Repex workload (non-MOBs)

- 40 This workload has been cut back by Ofgem in line with updated CBA guidance, with a reduction from 16 years to 11 years in GD3 to align with a 2037 cut-off date³³. This policy was first applied in RIIO-GD1³⁴, where a 24-year assessment was introduced, to provide a payback by 2037. This assessment was reduced to 16 years in GD2 and is now reduced further. The concept of 2037 'cut-off' has not been appropriately assessed in terms of costs and benefits for future consumers and since GD1, the number of customers has increased. The concept of a 2037 'cut-off' now places a material constraint on workload, which will drive a higher repair workload, increasing operating costs and associated bill impacts. As set out in our response to GDQ5, the 16-year payback needs to be restored in order to protect consumers until there is evidence of a declining number of customers using the network. Only then should a lower payback period be considered. Failure to do so will reduce safety, increase repair costs and increase methane emissions. For further engineering justification, please refer to document SGN-GD3-DD-ENG-SD017.

²⁶ SGN Submission of asset data repository 29th July, email to Vic Tuffen and Michaela Tevenan

²⁷ RIIO-3 Draft Determinations – Gas Distribution, July 2025, para 4.29, pg 78

²⁸ RIIO-3 Draft Determinations – SGN, July 2025, Appendix 1, pg 54

²⁹ RIIO-3 Draft Determinations – SGN, July 2025, Appendix 1, pg 57

³⁰ RIIO-3 Draft Determinations – SGN, July 2025, Appendix 1, pg 56

³¹ RIIO-3 Draft Determinations – SGN, July 2025, Appendix 1, pg 56

³² RIIO-3 Draft Determinations – SGN, July 2025, Appendix 1, pg 59

³³ RIIO-3 Draft Determinations – Gas Distribution, July 2025, para 3.69, pg 29

³⁴ RIIO-1: Final Proposals – supporting document – Outputs, Incentives and Innovation, Dec 2012, para 6.15, pg 34

Section 3 Correct the suite of errors in Repex unit costs

41 In this section, we set out three actions that Ofgem need to take to ensure appropriate allowances to deliver the Repex workload required within GD3. It is structured as follows:

- In section 3.1, we focus on how to address the gap between observed market rates for delivering Repex and the Repex allowances (Action 2a). We provide the latest evidence from the market on Repex costs; evidence of the contractor premium that we are subject to in the south due to an increasingly tightening labour market; and up-to-date data on the increased complexity of delivering Repex and the impact this is having on productivity, particularly in our Southern network.
- In section 3.2 we focus on the costs of delivering essential work to improve the safety of MOB's (Action 2b), including new legal requirements. We present evidence of the wide-ranging costs associated with MOB's workload and provide options for how this uncertainty could be addressed; and
- In section 3.3 we focus on addressing two sources of inefficiency – banding mix and abandonment rate – that are embedded within the forecasts and undermine the robustness of the cost assessment (Action 2c).

3.1 Address the gap to market in Repex allowances

42 In this section, we present the latest market evidence on the unit costs required to deliver the Tier 1 Repex programme and the gap between this and the allowances provided in the Draft Determination. We go on to evidence the unavoidable contractor premium we are subject to because we operate in the south of England. Finally, we demonstrate the increased complexity associated with the delivery of this mandatory programme, and evidence further regional factors that are significantly reducing productivity in our Southern network.

3.1.1 Tier 1 market evidence

- 43 The workload required to replace the remaining Tier 1 mains, so we meet the mandatory Iron Main Risk Reduction Programme (IMRRP) target by 2032 has been included in the Draft Determination. However, there is a significant gap between the unit costs used in the Draft Determination and those we put forward in our Business Plan, which were reflective of actual market rates. If the Draft Determination unit costs are maintained, it will result in us being underfunded by £213m in GD3 for mains lay activity.
- 44 Underfunding of the IMRRP in our Southern network also occurred in GD2. Table 1 below shows the allowed costs in GD2 and the actual unit costs that have been realised. Both are then weighted to the actual workload delivered to give a workload adjusted average unit costs.

Table 1: GD2 experience - Tier 1 Repex allowed unit costs vs actual unit costs (£ 23/24 price base)

	Scotland: 1,021km 5yr target		Southern: 3,001km 5yr target	
	Allowed unit cost £/m ³⁵	Actual unit costs £/m	Allowed unit cost £/m ³⁶	Actual unit costs £/m
≤3"	£138.63	£128.43	£129.79	£171.86
4"-5"	£153.46	£150.25	£143.67	£174.37
6"-7"	£223.47	£193.84	£209.21	£259.97
8"	£334.64	£249.93	£313.29	£357.61
Workload-adjusted average unit costs	£194.48	£174.28	£178.21	£215.36

Source: SGN analysis of licence conditions and latest 24/25 RRP submission

- 45 The workload adjusted average unit costs show that Scotland was able to deliver at a unit cost of approximately £20/m less than the GD2 allowed unit cost, while in Southern our costs were £37/m more than the GD2 allowed unit cost. However, the workload for Southern is three times greater than in Scotland. This led to a total saving of £25m in Scotland compared with a £187m overspend in Southern. Table 1, also shows a £41/m premium in the market rates for delivering Repex in the South compared to Scotland in GD2.

³⁵ Scotland Gas Networks Plc, Gas Transporter Licence Special Conditions, 1st April 2022, pg 87, inflated to reflected 23/24 values from 18/19 values cited in the licence condition for comparison purposes.

³⁶ Southern Gas Networks Plc, Gas Transporter Licence Special Conditions, 1st April 2022, pg 84, inflated to reflected 23/24 values from 18/19 values cited in the licence condition for comparison purposes.

- 46 It is not credible to attribute an overspend of this magnitude to assumed inefficiency, not least given the common ownership and management of the two networks. Both Scotland and Southern networks operate under the same corporate governance structure and consistent executive teams and are therefore directly comparable.
- 47 In Scotland, our GD2 Business Plan forecast Repex expenditure of £410m. We were awarded £401m and we have delivered for an anticipated £375m. In Southern, in our GD2 Business Plan, we forecast £1,230m for Repex expenditure and we expect to spend £1,229m in GD2. However, our allowances were 16% less than our forecast, totalling £1,034m.³⁷ This was because the cost assessment modelling determined a unit rate which did not reflect the cost of delivery in the south. We attempted to operate within our allowances; however, this constrained delivery and by the end of year 1 of GD2, we were behind our internal annual linear target by 14km, this increased to a 130km shortfall by the end of year 3.
- 48 This shortfall in southern delivery was due to an exodus of contractors from the market. By the end of year 2, 35% of our Southern Repex contractor teams (70-80 teams)³⁸ had moved to other markets, such as water, telecoms and electricity, where they could achieve better rates.
- 49 We recognised in year two that our allowances were not sufficient to deliver our targets, so we took action to transform our procurement approach. This started a challenging two-year journey of engagement and transformation to ensure that all aspects of our business were operating efficiently in service of the frontline. This led to a fundamental turnaround in our Southern network, with us increasing delivery of tier 1 iron replacement from 470km/year in year 3 to 658 km/year in year 4 and starting to make up the shortfall in delivery.³⁹
- 50 This higher rate of delivery will be sustained into the final year of GD2, with our procurement team rationalising the supply chain to bring down unit rates from the peak 2024/25 level of expenditure. However, rebuilding our supply chain and restoring delivery came at a cost, with us paying the market rates that significantly exceed the GD2 unit cost for Southern Repex delivery, with the total investment in GD2 forecast to outturn at £196m (19%) more than allowances.
- 51 Looking forward to GD3, market evidence shows that the unit costs to deliver Repex will continue to be significantly higher than the unit rates in the Draft Determination. Table 2, below, provides a comparison of the unit costs in the Draft Determination with the unit costs realised in the last two years of GD2 and our GD3 forecast.

Table 2: GD3 Draft Determination – Tier 1 Repex proposed allowance vs GD2 actual unit costs and GD3 forecast

	Workload-Adjusted Average unit costs	
	Scotland	Southern
Length Decommissioned (5yr target)	1,075 km	3,200km
GD3 Allowed	£149.96	£203.61
GD2 average last two years	£179.68(*)	£262.26(*)
GD3 Business Plan forecast	£179.14	£260.39

(*) NB In order to provide appropriate comparability the figures differ from the GD2 allowance comparison above as workload mix reflects GD3 forecast workload rather than GD2 delivered workload and is focused on costs of delivery in the last two years.

Source: SGN analysis of 24/25 RRP, SGN GD3 business plan and Ofgem GD3 Draft Determination

- 52 This table shows that the unit costs derived from the GD3 cost modelling and used in the Draft Determination are £150/m compared to a forecast of £179/m in Scotland, and £204/m compared to a forecast of £260/m in Southern. The Draft Determination costs are also below the rates we incurred in GD2 for both networks.
- 53 Our GD3 forecasts were developed following a detailed assessment of the rate cards used in the tender exercises undertaken in GD2 to restore our Repex delivery by independent consultants Deecon, a leading UK-based consultancy that works extensively across the utility sector, specialising in supply chain optimisation. Deecon's analysis provided a robust point of evidence based on actual market experience at the time.
- 54 Since the Business Plan submission, Deecon has updated its analysis to validate the cost of delivering the Tier 1 Repex programme. This second phase of analysis included eight months of additional rate card data with detailed analysis of 9,627 projects across Southern and Scotland with an associated £1.57bn investment and several

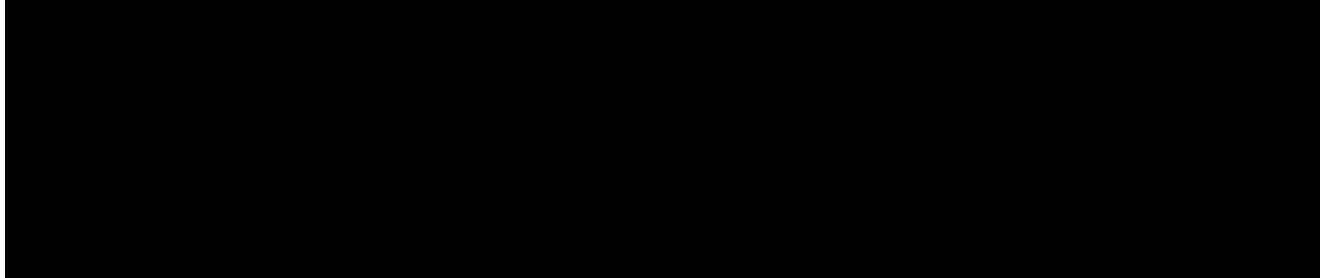
³⁷ SGN GD2 BPDT, Dec 2019, RIIO GD2 final determination Dec 2020, RRP July 2025

³⁸ SGN-GD3-SD-03 Workforce and supply chain resilience strategy, Dec 2025, pg46, para 226

³⁹ SGN-GD3-BPDT-02, Dec 2024, CV6.01 – tier 1 iron

methodological improvements.⁴⁰ In its updated report, Deecon⁴¹ find that the total Tier 1 cost forecasts fall within 3% of the estimate that was used to forecast GD3 costs, validating our Business Plan submission.

- 55 Finally, we have triangulated our GD3 forecast with the latest rates from our GD3 tender exercise carried out for Southern. This tender process employed a standardised methodology for evaluating recent contract performance across contractors, Repex delivery rate recovery and benchmarking against projected costs. The comparison between the latest market tender rates and our GD3 forecast unit costs are presented in the table below.



- 56 The table above shows that our forecast GD3 unit rates are within the range of the latest market evidence we have received through our tender process. The number of contractors responding to this tender process is sufficient to cover the GD3 workload expectations and as the award has not been finalised a range is presented. What is clear is that the market data demonstrates that the forecast unit rates within our Business Plan are robust, and the unit costs are up to [REDACTED] than set out in the GD3 cost modelling, which informed the Draft Determination.
- 57 If this is not changed, the errors of the past will be repeated meaning we will continue to overspend our allowances as it is clear from the market evidence that our mandatory Repex programme cannot be delivered at the Draft Determination modelled rates.
- 58 In our Business Plan we identified a number of normalisations and modelling adjustments that needed to be included in the cost assessment model to enable an accurate representation of the costs of doing business in the Southern region. These have not been appropriately included in the Draft Determination and have led to an under-representation of the efficient cost of completing the Repex programme in the Southern region. The two main adjustments are:
- Recognition that the regional aspect of contractor labour differs from direct labour as described in section 3.1.2 and that the Southern region is more exposed to a contractor market premium compared to other regions in the UK.
 - Recognition that there is a material regional difference in the productivity impact of complexity factors for completing the Tier 1 IMRRP⁴², as described in section 3.1.3, across the UK, and that by nature of the density of the Southern region, there is a greater exposure to complexity impacts compared to more sparsely populated parts of the UK.
- 59 These need to be factored into the cost assessment process to generate a more accurate portrayal of the costs of the notional company operating in the south of England, along with a correction of embedded inefficiencies that is set out in section 3.4, particularly around banding mix and abandonment ratios.⁴³

3.1.2 Tier 1 regional contractor market premium

- 60 Having identified the gap between the Draft Determination Repex unit costs and the market rates in section 3.1.1, we have further investigated the evidence of regional contractor premium in southern England, and its scale, to identify the appropriate adjustment needed to our allowances. As set out within our Business Plan, wage costs are currently normalised for regional differences according to the ASHE data set, which provides estimates for employee earnings⁴⁴. Our Business Plan evidenced that the GD2 cost modelling approaches demonstrated a regional bias towards using direct labour in the north of the country against the highly competitive market in the south of the country⁴⁵, where networks have increased reliance on contract labour.

⁴⁰ Deecon Consulting, Repex Cost Modelling – Mains Lay, July 2025, the improvements and their impact are set out in appendix 12.1

⁴¹ Deecon Consulting, Repex Cost Modelling – Mains Lay, July 2025

⁴² SGN-GD3-SD-08 Cost assessment and Benchmarking Approach, para 321-329 & 648-658, Ofgem cost bilateral 27/03/2025, CAWG 18 04/03/2025

⁴³ Ofgem cost bilateral 27/03/2025

⁴⁴ SGN-GD3-SD-08 Cost assessment and benchmarking approach, Dec 25, para 249, pg 37

⁴⁵ SGN-GD3-SD-08 Cost assessment and benchmarking approach, Dec 25, para 263, pg 40

- 61 The Draft Determination recognises that there are problems with the current approach of using the Office for National Statistics' (ONS) ASHE data, acknowledging that it does not capture self-employed labour (a major component of contractor labour). However, the Draft Determination does not propose⁴⁶ to make an appropriate adjustment for the errors in the approach.
- 62 Since the submission of our Business Plan, we have commissioned Economic Insight to explore the difference between the contractor and the direct labour workforce in more detail. The Economic Insight⁴⁷ report found:
- (a) There is an economic basis on which contract labour and direct labour differ, as they are not considered perfect substitutes, and based on economic theory, it is reasonable to anticipate that contract labour will command a premium in a tight labour market;
 - (b) There is evidence of a construction skills shortage across the UK, however, this is particularly pronounced in London and the South East. This supports evidence that GDNs face a regional premium for employing contracted labour in these regions that is above the premium faced for direct labour in the same region;
 - (c) That the regional premium is not picked up in the current regulatory model and that the reliance on the ASHE data for regional labour adjustment is not appropriate because it does not include self-employed workers, so it cannot represent where the regional costs of those self-employed workers vary. The report also identifies strong evidence to support an increasing premium for self-employed workers in London and the south east and identifies that the ASHE data misassigns non-London workers to the London regions, artificially dampening the real labour adjustment. This impact is exacerbated by the fact that contract labour should always price its services at the 'marginal price', whilst direct labour is more likely to price its services at the 'average price' due to friction in the market; and
 - (d) That as a price taker, SGN cannot avoid the higher contractor costs and that the contractor premium represents efficiently incurred costs that are not reflected in Ofgem's costs assessment approach.
- 63 In our GD3 Business Plan, we assessed that, using our Repex unit costs, the regional contractor premium between our two networks equated to c.10%⁴⁸. We have since updated our assessment, undertaking more detailed statistical analysis to remove the risk of overlap between regional complexity premiums. This updated analysis determines a more robust southern regional contractor premium of 6%, once isolating complexity factors⁴⁹.
- 64 Economic Insight reviewed this premium within the broader economic characteristics of the labour and contractor market and suggests that this is likely to be a conservative estimate of the impact of contract labour premium over a recognised direct labour regional adjustment. This conservatism is due to using Scotland as the basis from which to estimate the premium for Southern. Economic Insight points out that the premium could be adjusted upwards to recognise that Scotland has a higher wage than average, and secondly to recognise the evidence that year-on-year differences in contract labour have been increasing.
- 65 The Draft Determination raises the concern that applying a contractor uplift could reward GDNs for an inefficient labour model. The Economic Insight report demonstrates that the choice of contractor compared to direct labour is determined by market dynamics, of which the individual company has limited control. In a labour market as tight as London and the south of England where competition with other sectors, such as water is intensifying following record investment at PR24⁵⁰, there will be a dependency on the contractors – many of whom use self-employed labour. Networks operating in that region cannot avoid this and this labour comes at a premium. This is aligned with SGN's own experience of trying to build a direct labour workforce for delivering Repex in the south and the challenges of retaining that workforce after training.
- 66 This contractor market premium is a further 6% over the recognised direct labour regional adjustment for a company operating in the south compared to a company operating in Scotland, which must be accounted for within the cost assessment model to ensure that the different key sources of labour are captured in the cost assessment. We have provided in the supporting technical annex⁵¹ that sets out the approach for implementing a regional contractor premium within the Final Determination cost modelling suite to ensure appropriate assessment of efficiency for the areas in which we operate.

⁴⁶ RIIIO-3 Draft Determinations – Gas Distribution, July 25, para 5.88, pg 113

⁴⁷ SGN-GD3-DD-ECR-01 Economic Insight regional contractor costs

⁴⁸ SGN-GD3-SD-08 - Cost Assessment and Benchmarking Approach

⁴⁹ SGN-GD3-DD-TechSupp-02 - Assessment of Contractor Premia

⁵⁰ [Our final determinations for the 2024 price review – Sector summary](#)

⁵¹ SGN-GD3-DD-TechSupp-01 - Benchmark Model Changes Technical Guidance, section 3.1

3.1.3 Tier 1 regional productivity impacts of complexity

- 67 In this section, we evidence the complexity of the remaining Tier 1 Repex programme, which must be completed by 2032 and evidence how factors that increase complexity are more prevalent in the south, reducing productivity and increasing costs. We respond to the Draft Determination position and set out the adjustments we consider should be made to the cost assessment methodology.

Complexity within the Tier 1 Repex programme

- 68 In our Business Plan submission⁵², we identified eight complexity factors that are increasing the time and resources needed to deliver Repex, which reduce the productivity of contractors leading to higher unit costs. These are road crossings, stranded assets, stubs, service density, long services, riser proximity, cross road services and ductile iron. For both Scotland and Southern, we were able to establish the asset count and the length of each complexity factor in the remaining workload⁵³. From this assessment, we were able to evidence:
- The increasing prevalence of complexity factors in general, with complexity having an increasing impact on productivity over the workload as we progress to the final stages of the Tier 1 Repex programme; and
 - A significant regional impact, with projects in the south of England having significantly more complexity factors than those in Scotland. Analysis by MJM identified that 70% of projects in the South had one or more complexity factors impacting productivity compared to 49% of projects in Scotland. Furthermore, we identified that 43% of projects in the South had two or more complexity issues in a single project, compared to 24% in Scotland⁵⁴. Of the workload remaining in GD3, productivity will decrease c.6% in Scotland and by c.14% in Southern⁵⁵ compared to GD2 due to the complexity of our remaining workload.
- 69 This assessment clearly demonstrates that, under a common methodology and definition of workload, complexity has a significant regional characteristic that will have a material impact on the productivity of delivering workload and, as a result, will impact the cost of completing work in the GD3 period. This regional difference in complexity is not currently considered within Ofgem's cost efficiency determination or the regional adjustments that feed into it, highlighting an omission in ensuring Repex costs across networks are comparable.
- 70 Following submission of the GD3 Business Plan, Deecon conducted two further detailed reviews of complexity to independently assess the relationship between it and the costs we incur; the details of these can be found in GDO32 and GDO36. In the first of these, the statistical analysis of cost data⁵⁶ associated with 9,000 historical projects evidenced that ductile iron, cross road services and road crossings all had a statistical significance on cost throughout London, Scotland and Southern, with a highly significant impact in Scotland and Southern⁵⁷. The Deecon analysis verifies MJM's findings on the prevalence of complexity, identifying more incidences of complexity in the south, demonstrating a strong regional impact on productivity⁵⁸.
- 71 The second assessment undertaken by Deecon⁵⁹ was a qualitative analysis of 17 interviews with contractors and engineering managers to establish the impact of complexity factors on productivity. It compared the time (metres per week delivered) to undertake projects with different complexity factors with a standard base project (i.e. where the mains run down each side of the street and there are standard service lengths to each), to establish a percentage change in productivity. This showed that all eight complexity factors have a negative impact on productivity when looking at each complexity factor in isolation, ranging from 4% to 41%⁶⁰.
- 72 The survey also compared the difference between respondents in Scotland and Southern, with Southern respondents reporting a 31% higher impact for each complexity factor, on average, compared to those in Scotland. The survey therefore supports the finding that complexity factors have a greater impact on productivity in Southern compared to Scotland.

⁵² SGN-GD3-SD-06 Network Asset Management Strategy. Dec 2025 Section B2 and SGN-GD3-SD-08 Cost Assessment and Benchmarking Approach, Section F5, Dec 2025

⁵³ SGN-GD3-SD-06 Network Asset Management Strategy. Dec 2025, Table 51, para 100-104

⁵⁴ SGN-GD3-ECR-01 MJM Historical review of REPEX, Dec 2025, figure 4 and figure 5, pg. 15

⁵⁵ SGN-GD3-SD-08 Cost assessment and Benchmarking Approach, para 648-658, Ofgem cost bilateral 27/03/2025, CAWG 18 04/03/2025

⁵⁶ Repex Cost Modelling – Mains Lay, Deecon Consulting, July 2025, section 6.6.1

⁵⁷ Other complexity factors, such as Riser Proximity and Service Density, also have a statistical significance on cost, albeit less strong. Stranded Assets is a standalone complexity factor in which the relationship between the complexity factor and cost was not determined to be statistically significant.

⁵⁸ SGN-GD3-SD-06 Network Asset Management Strategy. Dec 2025, Table 51, para 100-104

⁵⁹ SGN-GD3-DD-ECR-04

⁶⁰ SGN-GD3-DD-ECR-04

Addressing complexity at GD3

- 73 The Tier 1 Repex programme must be completed by 2032, so opportunities to drive efficiencies will be limited as we work towards completing this mandatory workload in the time remaining.
- 74 It is essential that incremental costs relating to complexity factors are fully accounted for in GD3, so delivery is not constrained. We have been raising with Ofgem the impact of complexity in this remaining workload since our 22/23 RRP submission, and we are pleased that Ofgem is engaging with this issue. Underlying complexity has been included in all networks' Business Plans, and therefore, a notional component is embedded in the costs used to determine the efficiency of costs. However, we have evidenced regional differences in complexity, which are not appropriately normalised.
- 75 Ofgem recognise the challenges associated with compiling consistent data on complexity across networks in the Draft Determination and requested comparable evidence across networks. However, achieving this in the time available is unrealistic⁶¹ as it would require networks to share confidential contractor cost data, and it is therefore more appropriate for this comparison to be done by Ofgem.
- 76 To address the lack of normalisation in GD3, we suggest implementing a proxy driver (density) within a Totex model, enabling it to account for regional complexity. Decon recognises within its assessment of productivity the correlation between network density and the prevalence of complexity factors, and we have demonstrated this correlation to Ofgem through engagement in this issue. This is similar to the approach taken in RIIO-ED2 for a focus on low-carbon technologies and heat pumps, and to a proposal put forward by WWU in its Business Plan. Implementing such an approach would ensure a consideration of the clear regional aspect of complexity factors, and this would avoid a shortfall in delivery due to insufficient allowances at GD3.
- 77 The Draft Determination also raises questions on whether Tier 1 Repex has been funded in previous price controls to manage such complexity that has arisen towards the end of the IMRRP. We can be clear that this is not the case. As set out in the evidence submitted within our Business Plan, the Repex programme has continually evolved and changed in the prioritisation of risk and the inclusion of assets. A significant increase in complexity was created by the removal of Tier 2 and Tier 3 from the mandatory replacement programme in 2013.⁶² At the same time, a requirement to prioritise the removal risk in GD1 and target replacement of the mains most likely to give rise to a 'gas in buildings' event incentivised a focus on the smaller diameter mains close to properties. This significantly improved customer safety but placed less emphasis on the replacement of mains in more complex environments, further away from properties.
- 78 Failing to adequately reflect the impact of regional complexity is a substantial issue, and it will have implications for future work. As a result, it is important to start collecting data on a consistent basis across networks through the annual reporting templates. In the meantime, there is compelling evidence to demonstrate a regional element of the increase in complexity, using a proxy, during the GD3 period. In our supporting technical annex⁶³ we set out the changes necessary to implement the necessary changes to account for complexity on a regional basis.

3.2 Recognise the changing requirements to maintain safety in MOB

- 79 In our GD3 Business Plan, we submitted a significant increase in riser workload due to an increase in safety-driven interventions. The increase in workload is set out in Section 2, and additional information has been provided to Ofgem to evidence the need to undertake that work.
- 80 There is a clear requirement to undertake MOB workload; however, the nature of the workload and the costs that will be incurred are highly uncertain. MOB costs have always been poorly reflected in the data that is collected and the drivers that are used in cost assessment (the number of floors in a building). This uncertainty is then magnified by changing standards and expectations⁶⁴ that impact both the total workload and the design and cost of any repair or replacement.

⁶¹ March Ofgem/SGN cost bilateral recognised that the requirements for a consistent data set, as proposed in the Draft Determination, would be unachievable in the time available.

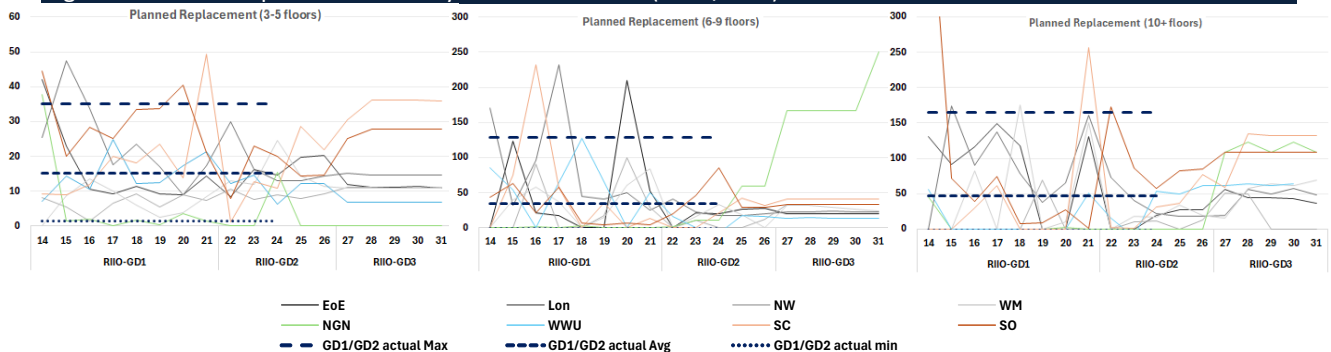
⁶² SGN-GD3-ECR-01 MJM Historical Review of Repex

⁶³ SGN-GD3-DD-TechSupp-01 - Benchmark Model Changes Technical Guidance, section 4

⁶⁴ Building Safety Act 2022, Grenfell Tower Inquiry: Phase 2 Report, Sept 2024, Amendments to the Building Act (1984) and England - Building Regulations for Fire Safety in Residential Home (updated 2025), Scotland – Building Standards Technical Handbook (2022) Section 2, Fire; updates to IGEM/G/5 (2023).

- 81 Figure 4, below, shows three graphs for the three categories of building height for which cost data is collected within the annual RRP. The individual lines are each network; however, the key message to reflect on from these graphs is the high level of volatility in the historical unit cost of riser replacement in all cost categories.

Figure 4: Planned replacement rate by number of floors (£000/riser) for all networks

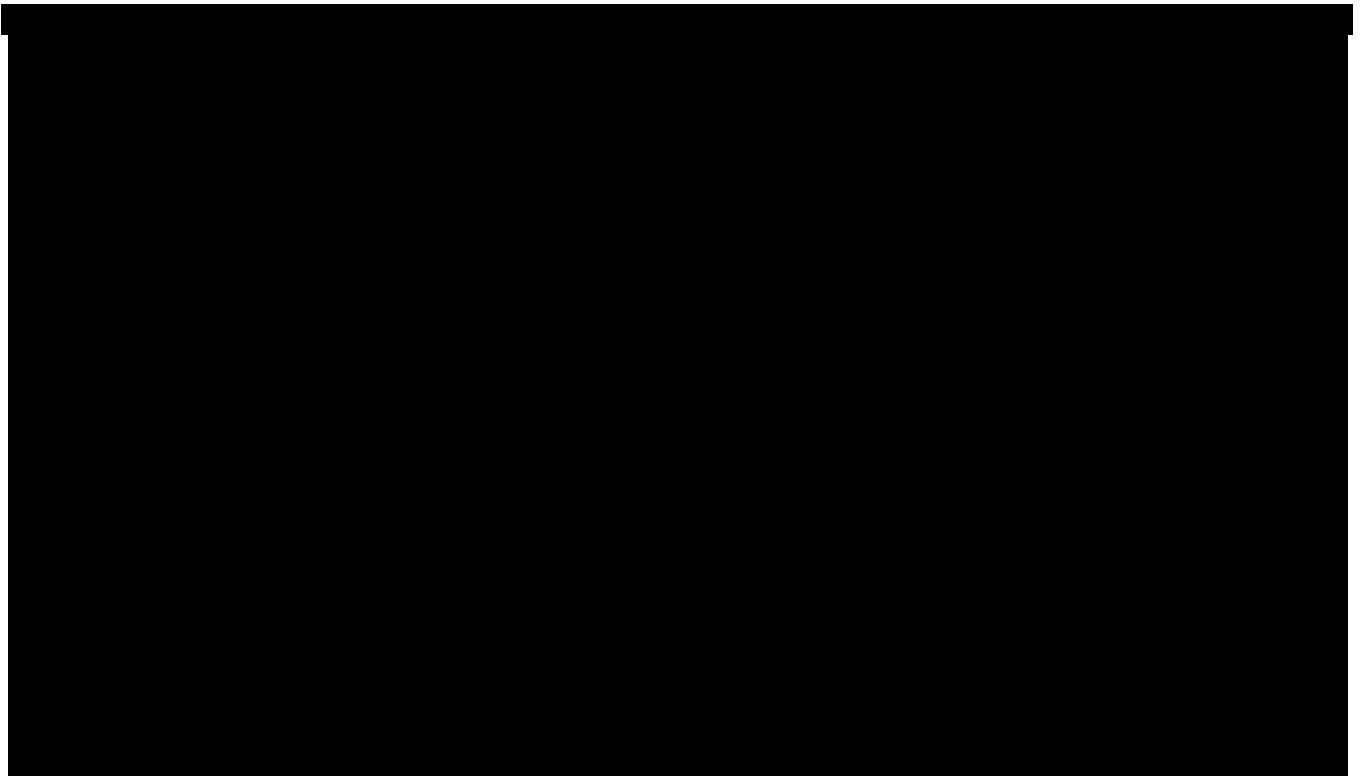


Source: SGN analysis BPDT

- 82 Each graph presents three lines: the average, the maximum, and the minimum unit cost historically reported by each network. In the 3-5 floor category, average unit costs for buildings range from the low thousands to £50k. In the 6-9 floors category, the volatility in observed costs ranges from low thousands to over £200k per/riser. Whilst in buildings greater than 10 floors, the volatility is increased further with values greater than £250k per riser. This masks an additional layer of volatility surrounding individual data points of actual jobs undertaken in that year. This clearly demonstrates a very high level of volatility in observed network costs, and that the current driver, the height of the building, used within the Ofgem cost assessment pack, is not an appropriate basis on which to reflect costs.
- 83 Given the increase in workload, legislative changes and the volatility in costs, we asked Decon⁶⁵ to undertake an extensive study into the cost drivers of MOB workload. This work builds on the analysis that they completed to inform our Business Plan submission⁶⁶ and incorporates the most recent data, updated sampling and improved data completeness. Decon's review included a deep dive into a representative sample of delivered projects setting out the prime costs (costs directly incurred by the project and excluding corporate costs that are necessary for project delivery) from a randomly selected sample of 25 projects that completed in the years 2023-25 (a time period selected to provide closer alignment to the implementation of the BSR building regulations). Decon's also reviewed a purposive sample - five high-cost projects specifically identified to explore cost dynamics. The results are shown in the figure below.

⁶⁵ SGN-DD-ECR-03 Decon Consulting REPEX MOBS Cost Modelling Report

⁶⁶ SGN-GD3-ECR-18 Decon Consulting Repex MOBS Cost Modelling Report



- 84 The updated analysis⁶⁷ showed the average riser unit cost (all buildings) was [REDACTED]. However, as shown in Figure 5, there is a significant range, and from a random sample of 10+ storey MOB, prime costs have a mean cost of [REDACTED] with an upper quartile range of [REDACTED] between the lowest and the highest cost projects. With 3-5 storeys the mean cost is [REDACTED], with a range of [REDACTED] and for 6-9 storeys, the mean cost is [REDACTED], and the range is [REDACTED].
- 85 The analysis also used a purposive sample of high-cost sites to explore cost drivers. This sample had a mean cost of [REDACTED] and a range of [REDACTED] between the lowest and highest cost projects. It was identified that for the body of sites that had extremely high costs, the major cost driver was the approach to scaffolding, and contractor costs. There are several factors that influence scaffolding requirements, including height, the nature of the building, the structure of the building and whether the riser can be replaced internally or externally. For example, a lower-rise building with a greater proportion of laterals (horizontal mains being fed by the vertical riser that runs along the side of the building) is likely to have higher scaffolding costs than a taller building with single or multiple risers running up the side of the building to supply customers.
- 86 Deacon's review identified that the Building Safety Regulator (BSR) is driving stricter oversight of work on high-rise buildings, mandatory approvals and safety documentation that risks delays, increased scaffolding time and administrative overheads. It also highlighted a growing shortage of scaffolders and the costs of new compliance criteria driven by Public Procurement Reform. Together, these regulatory, labour and procurement changes are increasing the cost of riser work.
- 87 There is also a strong regional element associated with some of these characteristics. For example, in Scotland the MOB housing stock is uniquely dominated by tenements, which are historical low-rise MOB that often have extensive laterals built into the building fabric and can be particularly challenging to address. Furthermore, Scottish legislation places onerous requirements that differ to those in England, and the high threshold for high-risk buildings is lower than England (>11m.⁶⁸ rather than >18m.⁶⁹).
- 88 As set out in section 2 the workload needs to be delivered, however the cost drivers currently in the cost assessment model are inadequate. Furthermore, as the workload was disallowed in the Draft Determination there has been no appropriate opportunity to explore differences in costs exists. It is our view that important cost drivers which must be considered are:

⁶⁷ SGN-GD3-DD-ECR-03 DEECON – Repex Cost Validation – MOB and Risers, July 2025, pg 3

⁶⁸ IGEM/G5 and Scottish Government, Building Standards Division, Domestic Technical Handbook, January 2025, pg.107 and pg.580

⁶⁹ Building Safety Act 2022

- regional standards for building and fire (Scotland vs England);
 - whether the intervention is pro-active or reactive;
 - the length of vertical riser, horizontal risers and laterals;
 - whether the replacement is internal or external;
 - where replacements are external – scaffolding, local planning requirements/listed status, associated mains lay, and internal remediation work costs; and
 - where replacements are internal – fire proofing, ventilation, building modification and internal remediation work costs.
- 89 Each of these factors will have a significant impact on costs; however, while the legislation is in place, there is significant uncertainty in how it will be implemented in practice, which drives further cost uncertainty.
- 90 Additional uncertainty is also created through the extent of opportunities to move customers from natural gas to electricity, or the potential to replace gas risers with an alternative source of energy (something that is a focus of our proposed innovation in GD3). If no appropriate alternative exists, we will need to complete the replacement for safety reasons.
- 91 Together, these uncertainties will have a significant impact on both the workload and the costs. Given these uncertainties extend beyond the legislation itself, we believe that it is more appropriate to utilise the HSE reopener mechanisms to address these wider uncertainties and ensure the appropriate level of funding is provided to networks to afford an appropriate level of protection to both customers and investors while we improve data quality on the cost factors set out above.
- 92 As the work needs to continue, we propose to have the initial two years' workload funded in the Final Determination for both reactive and proactive workload. We then propose to use the HSE reopener to cover the majority of MOBs workload, propose a specific reopener window in January 2028 to enable data to be collected and for future workloads to be established.
- 93 During this period, we would recommend that we improve data collection across networks. Consistent data should be collected across a broader range of cost drivers through the annual RRP submission. This data will help to inform future price controls and the submission of MOB workload within the HSE reopener.
- 94 Whilst not our preferred approach, an alternative would be to recognise the uncertainty in the costs, the risk of overspend, and the building-specific nature of the MOBs costs by changing to the sharing factor (TIM) for MOBs specific costs. In this instance, an overspend could be shared on a 90:10 basis (with customers taking 90% of the cost of under or over performance and networks taking 10%) rather than the current 50:50 basis.

3.3 Recognition of an efficiently forecasted Business Plan - banding mix and abandonment ratio

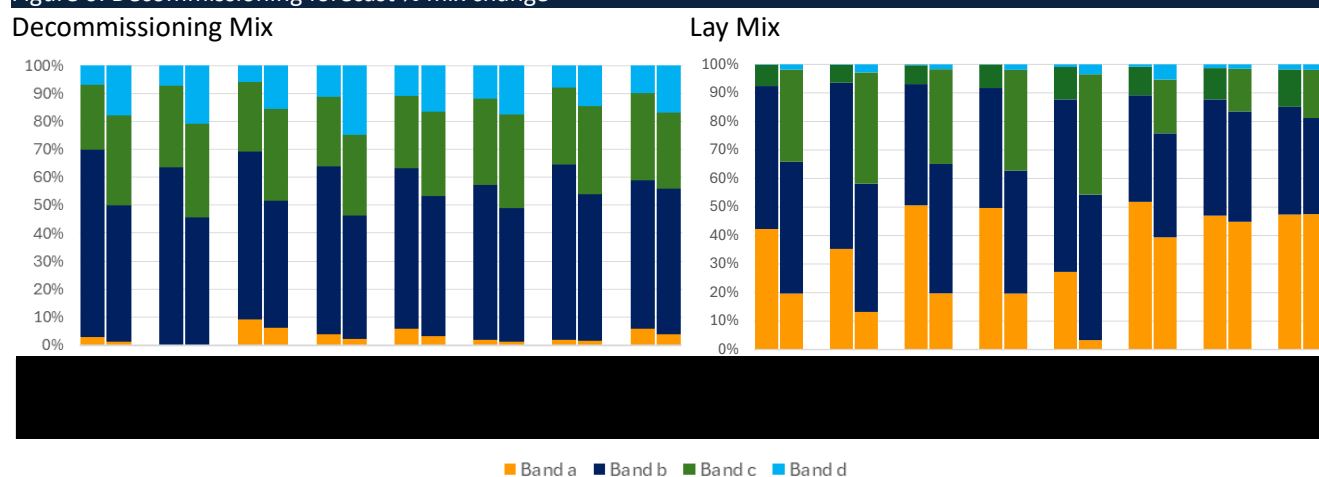
- 95 The Draft Determination⁷⁰ has drawn attention to and asked for clarification of the existence of two sources of inefficiency that are embedded within the forecasts provided by some networks, which would not otherwise be picked up through the cost assessment methodology. We welcome Ofgem's recognition of this, as we consider that these forecast inefficiencies – the banding mix and the abandonment ratio – undermine the robustness of the cost assessment and must be addressed in the Final Determination.
- 96 Since the GD3 Draft Determination, we can see further evidence that the forecasts put forward for both banding mix and abandonment ratio provide a forecasting-based advantage to certain companies that is not adequately controlled. This had a material impact on the allocation of allowances within GD2, and analysis suggests this material impact continues in the GD3 Draft Determination.
- 97 Both these errors have a secondary impact on the Business Plan Incentive (BPI) assessment. These forecast design inefficiencies have an impact on the outcomes of the regression analysis and result in unjustified financial benefits for those networks that ultimately deliver a mix comparable to that delivered in GD2, rather than their GD3 forecast. This runs counter to and undermines the objectives of the BPI incentive. It is our view that networks that present a more efficient workload should be rewarded through the BPI.

⁷⁰ RIIO-3 Draft Determination – Gas Distribution, GD 5.224, pg 142

3.3.1 Banding mix

- 98 The current approach enables networks to include an elevated (more expensive) banding mix within their Business Plan forecast but then deliver actual workload in line with historical averages. This was apparent in one company's forecasts.^{71,72}, where it was identified that an elevated banding mix was included in the forecasts, and subsequently demonstrated that the actual workload returned to historical levels. The result was that the network received an additional allowance that they would not have been entitled to if they had accurately forecast their banding mix.
- 99 This issue occurs because the cost assessment methodology utilises diameter bands of 'lay' workload as a driver to determine an allowance for delivering Repex. Whilst the Price Control Deliverable (PCD) utilises the diameter band of 'decommissioned' workload to reflect changes in delivery. The setting of the decommissioned unit rates within the PCD locks in the mix of 'lay' workload that is calculated through the cost assessment modelling. By overstating the banding of 'lay' workload, it is possible to create the appearance of greater efficiency within the cost modelling suite that can then be reversed out by completing the work at a smaller diameter than forecast and then realised as a financial benefit.
- 100 We forecast our lay workload based on our historic averages, which represent efficient unit rates for decommissioning. There is evidence that, in GD2, some networks submitted a materially different mix of lay band forecast workload compared to what has been historically delivered. We now have four years of actual data, which shows that they delivered a significantly different banding mix in practice, with forecasts up to 18% higher than actual delivery in some cases.
- 101 Data presented in GDQ40 shows a significant swing in GD3 lay forecasts from lower 'band A' and 'band B' to the higher cost 'band C' and 'band D'. If these swings are not reflected in actual delivery, and actual delivery reverts to historical averages, the forecasts in the Business Plans will inflate the lay cost used in determining the Repex synthetic cost driver and make the forecast delivery appear more efficient. This would suggest a roll-back from the efficiency being delivered while completing their Repex programme. The inefficiency of the forecast was not challenged within the econometric modelling approach, as the driver was influenced by the input of lay band mix.
- 102 The different network plans are shown in the figures below, Figure 5, which shows the change between GD2 actual and GD3 forecast for decommissioning-mix and lay-mix for delivering the Tier 1 Repex programme.

Figure 6: Decommissioning forecast % mix change



Source: SGN analysis of Business Plans submissions

- 103 These figures show that under the 'decommissioning mix', networks are broadly consistent. There is some decommissioning of the highest diameter bands (c and d) and relatively limited decommissioning of the lowest diameter band (a). This is to be expected as with decreasing demand for gas, and improvements in network

⁷¹ BPD data Inconsistencies Sept 2020

⁷² Email Mike Bedford to Mike Wilks, 13th January 2021 with attachment "Repex Lay Mix in GD2"

design, it should be possible to decommission a large diameter 'd' main and replace it with a smaller diameter and less costly band 'b' or 'c' main.

- 104 However, we can see from the actual 'lay mix' that 40-50% of the mains that have been laid are the smallest band 'a' with a much lower proportion of the largest 'c and d' bands. This has reduced the cost of delivering the work and a higher percentage of bands 'a' and 'b' to bands 'c' and 'd' indicates a higher level of delivery efficiency.
- 105 In the forecast 'lay mix' figure, it is very clear that some networks are forecasting that they will become less efficient in GD3 and have significant drops in the 'b and a' delivery and a significant increase in band 'c'. Whilst other networks have a much higher level of consistency between the two.
- 106 In GD2, for some networks a similar change in 'lay mix' forecast was noted, and they reverted in line with historical performance (which is shown as the actual in the figures above), realising the financial benefit of laying 'band a whilst being funded for 'band b'. Because the regression analysis is completed on 'decommissioning mix', this forecast inefficiency was not picked up within the assessment process. As the networks with the largest distortions are currently setting the efficiency frontier in GD3, they are artificially extending the frontier down, causing SGN extra catch-up efficiency of approximately £120m in allowances.⁷³
- 107 Ofgem has proposed to adjust the banding mix issue, if there is insufficient evidence to support these changes in forecasts.⁷⁴ We can identify no engineering rationale for large changes from historic lay-mix for any individual network set out above.
- 108 Our recommended remedy is to use a single level of design efficiency based on historical notional averages applied to all networks, providing an incentive to networks to implement a more efficient design and penalising networks that aren't. In our supporting technical annex⁷⁵ we set out the changes necessary to implement this change and ensure that networks are compared on a consistent basis.
- 109 Alternative remedies are that (i) networks could be required to restate their forecasts in line with good engineering design efficiency and provide an engineering rationale to any variation, or (ii) networks that have maintained a high level of design efficiency [REDACTED] should be allowed to recalibrate to align with the other networks. It is our view that at this stage in the process, there is a greater risk in implementing these alternative remedies compared to our proposed remedy.

3.3.2 Abandonment ratio

- 110 A similar issue was identified with the abandonment ratio, a second area of forecast efficiency with similar characteristics to the banding mix issue above. All networks have an opportunity through efficient design to lay less mains than they decommission, i.e. to abandon a section of the network which is no longer required. A ratio: (i) greater than 1 indicates that 'mains decommissioned' was greater than 'mains laid'; (ii) and a ratio of 1 shows that for every meter of 'mains decommissioned' was matched by a meter of 'mains laid';, and (iii) a ratio of less than one suggests that for every meter of 'mains decommissioned' more than a meter of mains were 'laid'.
- 111 A higher ratio (i.e. where mains decommissioned exceeds the mains laid) identifies greater design efficiency and – if it is included within the forecasts for GD3 – will result in a lower cost to the consumer. If it is not included in the forecasts but is delivered later, then it will be realised as a financial benefit to the network. As with the banding ratio issue in 3.3.1, deviations between forecast and actual abandonment rates, do not show up as an inefficiency in the regression analysis, which is run on decommissioned costs, as it is an efficiency (i.e. reduction) on the lay costs.
- 112 The different network plans are shown in Figure 7 below. This shows the historical performance of all networks, the realised max, min and average abandonment ratio over the GD1 and GD2 period and how this compares with forecasts set out within the GD3 Business Plan.

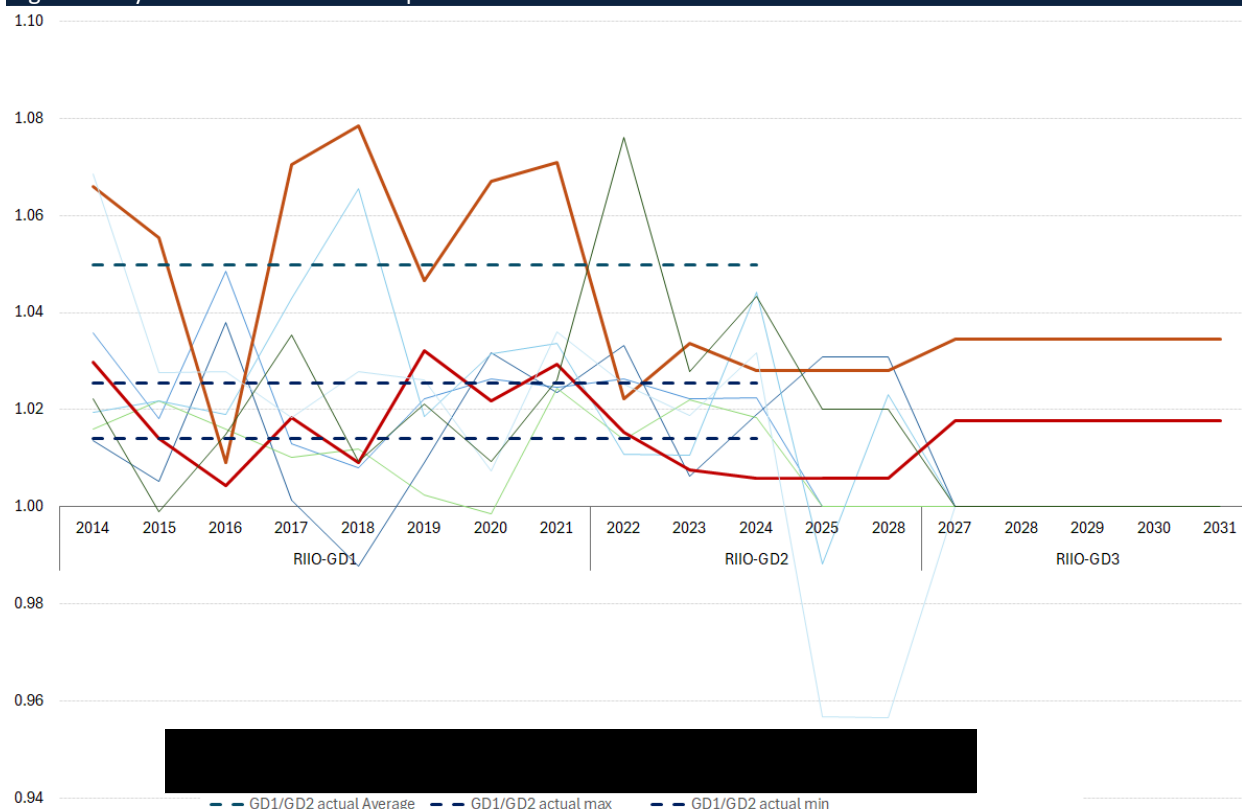
⁷³ Assessed by aligning all networks to their specific historical banding mix within the Repex synthetic driver utilising Ofgem's DD cost modelling suite.

⁷⁴ RIIO-3 Draft Determination – Gas Distribution, GD 5.224, page 142

⁷⁵ SGN-GD3-DD-TechSupp-01 - Benchmark Model Changes Technical Guidance, section 3.2

SGN Draft Determination response overview

Figure 7: Lay to abandonment ratios per network



Source: SGN analysis of Business Plan submissions

113 The figure above shows that, across GD1 and GD2 actuals, there has been an average ratio of 1.026 across networks. The worst-performing network delivered an average ratio of 1.014. So, for every meter of 'mains decommissioned' there has been an average of 0.974 meters of 'mains lay'. This represents a suitably efficient manner of doing business. It also shows that all networks apart from Scotland and Southern are proposing to move to a 1:1 ratio for GD3, i.e. that they are proposing lower 'design efficiency in GD3 than they were historically, and lower design efficiency at GD3 than SGN are proposing.

114 We submitted an ambitious plan to drive customer value in GD2, resulting in c.65km lower Tier 1 lay workload compared to our forecasts. By contrast, it has become clear in subsequent annual reporting that networks that forecast an abandonment ratio of 1 have subsequently delivered a higher abandonment ratio during the GD2 period. For some networks, this resulted in the GD2 determination allowing an extra 173km of Tier 1 lay workload, which they have had the chance to outperform during delivery.

115 As with the banding mix impact set out above, the abandonment ratio is a design inefficiency, which will not be picked up through the cost assessment process. Our abandonment ratio for GD3 is 1.018 for Southern and 1.034 for Scotland, with consideration of historically performed abandonment levels. This contrasts with a 1:1 ratio of other networks. This is the equivalent of a 2% to 4% efficiency improvement that is picked up for SGN relative to the other networks. If we applied the same ratio as other networks over the 4,000 km of Repex to be delivered in Southern and Scotland, we would be charging the customer for 94km of Repex unnecessarily, at a cost of £21.5m.

116 As with 3.3.1, Ofgem has proposed to adjust this if there is insufficient evidence to support these changes in forecasts.⁷⁶ and we can identify no engineering rationale for large changes from historic lay-mix for any individual network set out above.

117 Our recommended remedy is to use a single level of design efficiency based on historical notional averages applied to all networks, providing an incentive to networks to implement a more efficient design and penalising

⁷⁶ RIIIO-3 Draft Determination – Gas Distribution, GD 5.224, page 142

networks that aren't. In our supporting technical annex⁷⁷ we set out the changes necessary to implement this change and ensure that networks are compared on a consistent basis.

Section 4 Correct allowances to reflect operational reality

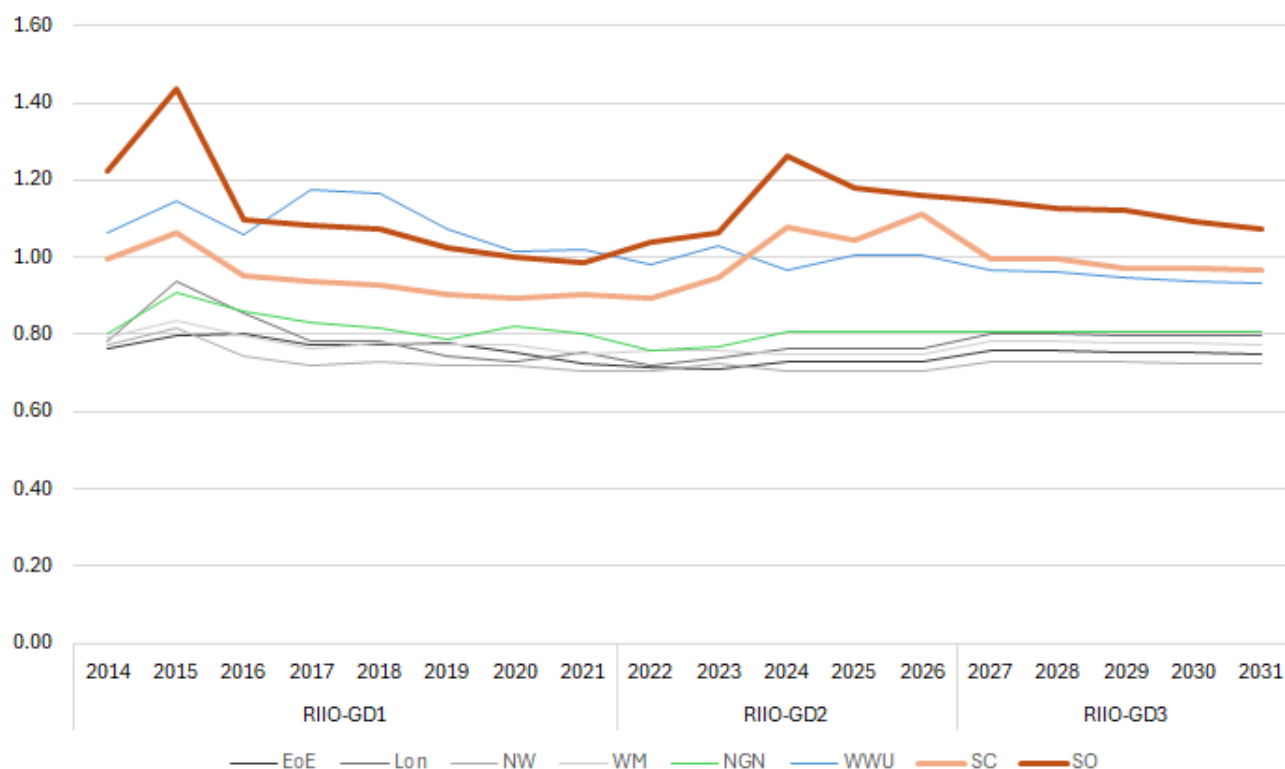
118 This section considers further appropriate Totex adjustments and presents three changes that need to be made to reflect how a notional company should operate in practice.

- In section 4.1, we discuss the limitations associated with reports as the driver for determining efficient repair costs and present length of metallic main as an appropriate alternative (Action 3a);
- In section 4.2 we present the case for recognising appropriate costs associated with regional workload and streetworks, which better reflect the changes we are experiencing, particularly within our Southern network (Action 3b); and
- In section 4.3 we explain the importance of reflecting an appropriate ongoing efficiency (OE) requirement, highlighting errors which have resulted in the approach to setting OE in the Draft Determination (action 3c).

4.1 Correct the repair cost driver

119 The repair cost driver is currently determined by the number of total external condition reports. These are publicly reported escapes (i.e. called into the emergency response line), where a repair is required and undertaken. The figure below shows the respective repair-to-report ratio across the networks.

Figure 8: Total condition repairs to report ratios



Source: SGN analysis of Business Plan submissions

NB – there is an error in the modelling suite regarding the number of repairs; once this is corrected, the ratio will be above one.

120 Figure 8 shows that there is a consistent differential between the number of repairs carried out per report.

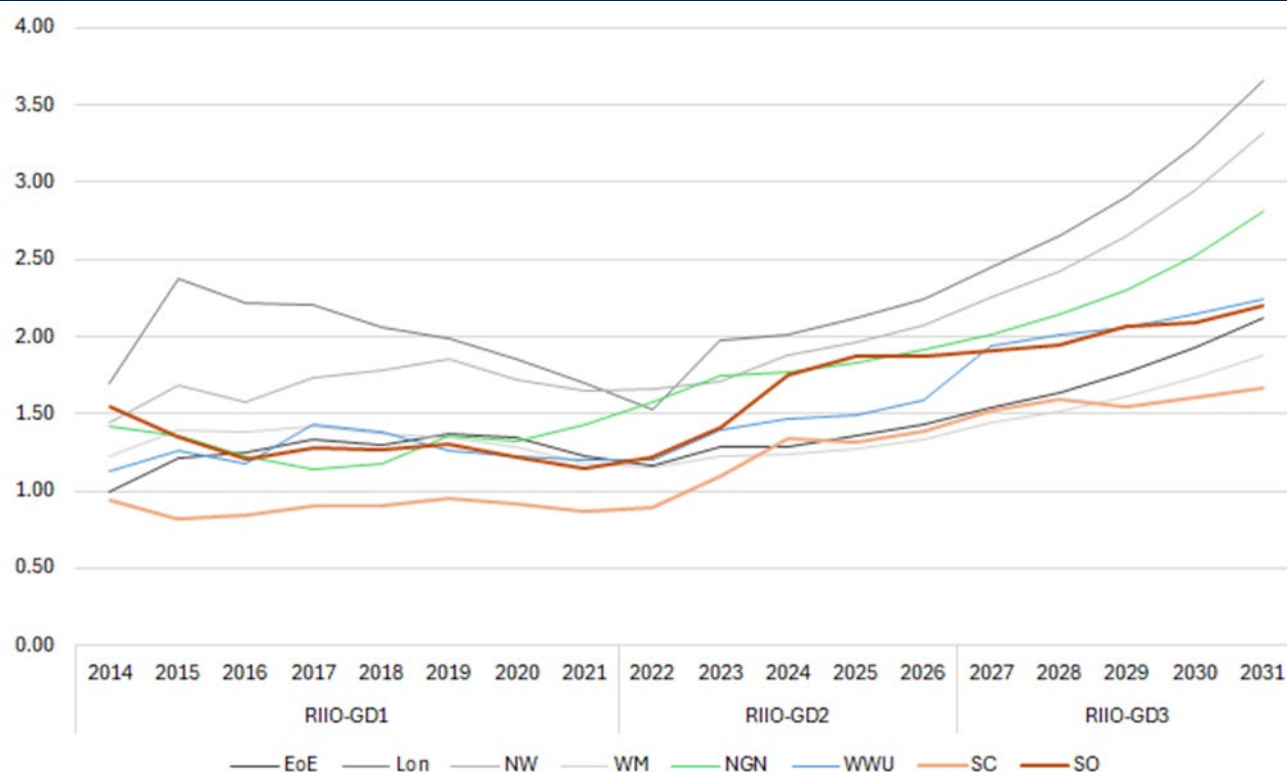
Scotland, Southern and WWU have consistently higher repair-to-report ratios compared to the four Cadent networks and NGN. It also shows there is a clear disparity in networks' total conditional repairs undertaken per

⁷⁷ SGN-GD3-DD-TechSupp-01 - Benchmark Model Changes Technical Guidance, section 3.2

external condition report, and there is no engineering rationale for why a network should have a higher or lower number of repairs per report.

- 121 It has been confirmed and verified in recent Ofgem workshops that gas networks have different internal policies for when a repair should be reported by a GDN operative as a new report. When an engineer attends a site following a public report of a gas escape, they will first identify whether a repair is required or not. They will also do a sweep of the broader area to identify if there are any more gas escapes that require repair in the local vicinity. Given that escaped natural gas may migrate a significant distance through ducts and corrosion tends to impact the same part of the network, an initial excavation may be extended to include more than one repair. Alternatively, multiple excavations and repairs may be required to fix all the leaks in a given area. If all these repairs are in the initial sweep area, some networks will attach all the repairs to the same initial public report. Other networks may have an alternative internal process as to when the engineer should call in a new report for each additional repair identified.⁷⁸
- 122 As allowances are determined by the number of external condition reports, such differences in company policy (an endogenous factor) will create a disparity in the number of reports created. The Draft Determination is therefore incorrect in concluding that using the total condition reports to explain repair costs within the CSV continues to meet the criteria for being a robust driver. As explained above, the process through which an extra report is called into the gas emergency number cannot be considered 'outside of management control' or 'consistently reported' as suggested within the Draft Determination. Attempting to use such a flawed metric will inevitably result in an incorrect allowance at GD3 and does not achieve the stated effect of the driver Ofgem has selected.
- 123 We agree with Ofgem that the cost driver should be exogenous, in that there is little or no impact that company policy would have on the numerical value of the driver for any given set of repairs. We have considered several alternative approaches that remove 'human' or endogenous aspects of the process. These were (i) repairs per customer, (ii) repairs per network length, (iii) repairs per MEAV (modern equivalent asset value), (iv) repairs per throughput and (v) repairs per km of metallic main. We compared the outputs (GDQ39), which shows that when the endogenous aspect is removed, then the respective ratios become less determined by ownership group and less uniform. All of these alternative configurations have less risk of alternative company-specific practices and processes distorting the repair cost driver as they are fully exogenous.
- 124 However, as well as being exogenous the cost driver must be justified by a strong engineering rationale as to why there is a link between the driver and the cost incurred (and we agree with Ofgem that a clear causal relationship with the activity is needed). The only parameter we have identified that meets both criteria is repairs per length of metallic mains, on the basis that it accounts for approximately 90% of total repairs undertaken (PE accounts for approximately 80% of total network length and only 10% of repairs). We consider this should replace reports as the repair cost driver, as it has the advantage of being exogenous, enabling closer scrutiny of underlying trends and whether they align with the anticipated roll out of replacement work, rates of asset degradation and anticipated leakage. This is shown in the figure below.

⁷⁸ It should be noted that where networks opt to call in a new report more frequently, this may also support their delivery of the 97% emergency standard.

Figure 9: Total repairs per metallic mains length

Source: SGN analysis of GD3 Business Plan Data Templates.

125 Most networks have an increasing ratio of repairs per km of metallic main. This is to be expected to a degree on the basis that as networks increase their replacement of iron mains. In our supporting technical annex⁷⁹ we set out the changes necessary to implement this change and implement a consistent basis for repair cost assessment.

4.2 Recognise the appropriate costs associated with regional workload and streetworks

126 In the GD3 costs assessment model there are a number of regional adjustments that are implemented to reflect the regional costs of doing business. However, corrections are required to how some of these adjustments are made to more accurately reflect the cost of operating an efficient business in the South of England. The two which are most relevant are regional workloads and streetwork costs.

4.2.1 Regional workload

127 There is significant variability in workload between regions according to the geographical characteristics of each region, the asset types, the age of construction and the associated rate of deterioration. These characteristics will determine the workload that needs to be implemented during the GD3 period to maintain the appropriate level of safety and, as a result, the workload will vary significantly. Given these physical variations, it is not reasonable to assume a uniformed 'notional company' workload and the workload needs to be applied on a network basis. This is demonstrated within the GD3 Business Plans with the ratio of Repex of Totex ranging from 32% to 53% across networks. However, the main driver of workload (the composite scale variable (CSV)) assumes a national average that is applied across all regions. This has a significant distortion on scale variable, which needs to be adjusted to align with the actual workload carried out by the region. In our supporting technical annex⁸⁰ we set out the changes necessary to implement this change.

⁷⁹ SGN-GD3-DD-TechSupp-01 - Benchmark Model Changes Technical Guidance, section 6.1

⁸⁰ SGN-GD3-DD-TechSupp-01 - Benchmark Model Changes Technical Guidance, section 7

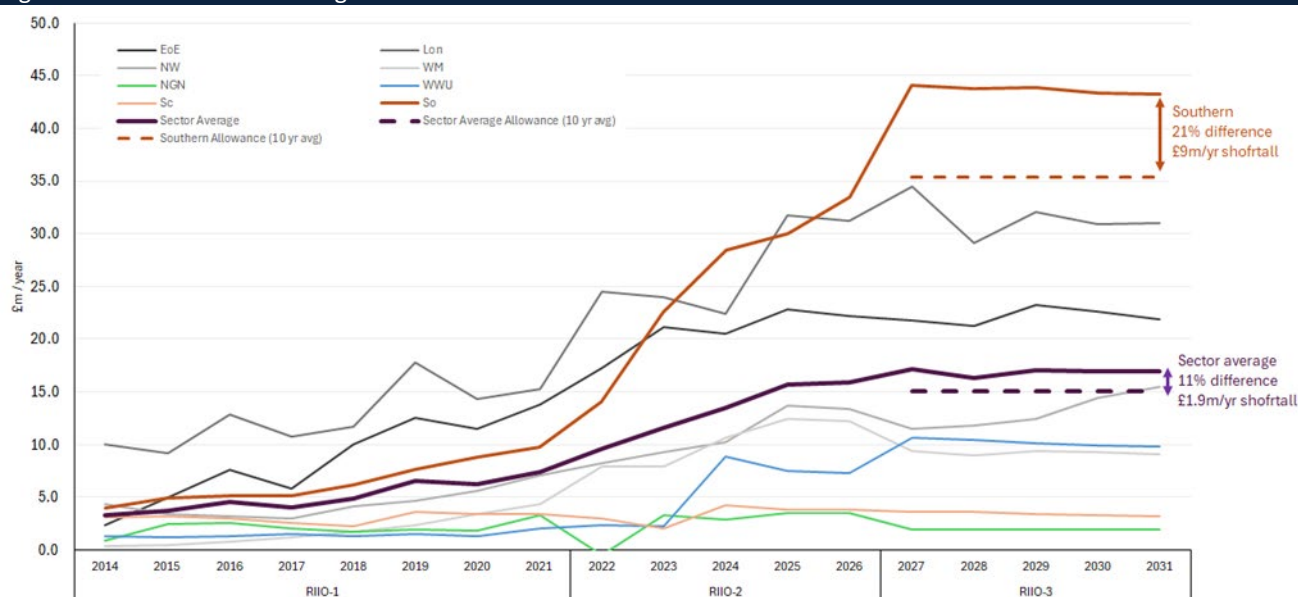
- 128 Within our Business Plan we conclude⁸¹ there is a need to review the factors used for determining the pre-modelling normalisation adjustment for urbanity productivity. This factor was set at GD1 using SGN derived data and we believe it requires updating to reflect the latest pressures of operating within our Southern region. We utilised our latest travel data differential between Scotland and Southern to evidence that the factor for urbanity productivity should increase from 1.04 to at least 1.08 for the GD3 period.
- 129 We note Cadent have suggested an alternative approach to claim for pre-modelling specific claims to enable normalisation ahead of efficiency assessment, similar to the 'Nature of Streets' approach used within ED2. We have analysed this approach and note a materially similar outcome, with either an updated urbanity productivity factor as suggested in our Business Plan or a 'Nature of Streets' approach assuming we receive a proportionally similar adjustment for the proportion of the network that operates within the London area.
- 130 As such, we consider that either approach would be suitable for pre-modelling normalisation within GD3. We will submit our own claims to Ofgem to support testing of a 'Nature of the Streets' change. The necessary adjustment is set out in our supporting technical annex⁸².

4.2.2 Streetwork costs

- 131 Within the Draft Determination, the decision was made to consider streetworks over a 10-year period⁸³ from 2021 to 2031. This would be a reasonable approach if costs were relatively stable over time and there was no material underlying trend (either positive or negative) in costs. Analysis carried out by Decon assessed the impact of streetwork costs over time, and how policy changes are driving cost changes on an individual project basis

- 132 The figure below shows the increase in streetwork costs over time and the 12% compound annual growth rate.

Figure 10: Streetwork costs long-term trends



Source: SGN analysis of GD3 Business Plan Data Templates.

- 133 This demonstrates clearly that the costs of streetworks are increasing and that once schemes have been introduced, both the costs of permitting and lane rental increase, the permit conditions become more exacting, and the cost of contraventions become more expensive. For local authorities who otherwise face tight constraints on their budgets this becomes a revenue-raising opportunity to support road maintenance budgets⁸⁴.

⁸¹ SGN-GD3-SD-08 Cost assessment and benchmarking approach, Dec 25, pg.45

⁸² SGN-GD3-DD-TechSupp-01 - Benchmark Model Changes Technical Guidance, section 5.2

⁸³ RIIO-GD3 Draft Determinations – Gas Distribution, Para 5.260, pg 150

⁸⁴ <https://www.gov.uk/government/consultations/street-works-fines-and-lane-rental-surplus-funds/outcome/bbed3de3-6c4a-4ccc-8b1c-30cae3b69e1d>

134 The figure shows that for the sector average, utilising a 10-year average will understate forecast costs by £1.9m per year (11%). For networks with steep increases in streetwork costs, such as in the southern region, using the 10-year average will understate streetworks by £21m per year (21%).⁸⁵

135 Streetwork costs are outside of networks' control and have been increasing rapidly in certain regions as councils recognise the potential to generate revenue. The forecasts need to be maintained, and this will also support alignment with GD3 reopener. The necessary adjustment is set out in our supporting technical annex.⁸⁶

4.3 Reflect an appropriate ongoing efficiency requirement

136 In its Draft Determination, Ofgem has maintained an OE target to cost allowances (i.e. baseline Totex) as a post-modelling adjustment.⁸⁷ This has been applied on a compound basis from 2024/25, the first year of forecast costs. The Ofgem assumption is based on a report completed by Grant Thornton, which estimated an OE range using quantitative growth accounting analysis of 0.1%-1.3%. The Draft Determinations considered this range too broad and adopted a narrower range (0.7% to 1.3%).⁸⁸ utilising NGET's proposal of 0.7% as the bottom of the range, despite it being the highest proposal of all the networks presented.

137 There are a number of errors in the approach set out by the draft determination.⁸⁹ These are:

- (i) It is inappropriate to rely on precedent as the basis for determining the ongoing efficiency requirement, the assessment must be based on analytic methods and data.
- (ii) The assessment is upwardly biased as its assessment does not cover a full business cycle, rather, it removes the years of 2008 and 2009 as 'outliers' even though they are consistent with total factor productivity (TFP) growth.
- (iii) The assessment is upwardly biased as it selectively chooses the upper end of the range. This is not appropriate, particularly for networks facing increasing restrictions (set out above) on its ability to replace assets with new and more efficient assets.

138 We submitted evidence⁹⁰ in support of the 0.5% identified as the OE challenge within our Business Plan, which represented the midpoint of a range from 0.3% to 0.8%. The selection of 1% per annum is outside of this range and it is only through a series of errors that the Draft Determination can establish that a range of 0.7-1.3% is a reasonable basis from which to then determine 1% as an appropriate mid-point. The errors in this approach have been set out in an accompanying report by Economic Insight⁹¹, and as a result, the Draft Determination erroneously reduces allowances by £88m compared to the 0.5% OE challenge set within our Business Plan. We therefore maintain that 0.5% is an appropriate level of OE.

⁸⁵ It should be noted that this understated cost will not be picked up in the streetworks reopener, which limits costs eligible for submission to costs associated with new schemes.

⁸⁶ SGN-GD3-DD-TechSupp-01 - Benchmark Model Changes Technical Guidance, section 5.1

⁸⁷ RIIIO-3 Draft Determinations Overview document, July 2025, pg 90

⁸⁸ RIIIO-3 Draft Determinations Overview document, July 2025, para 8.29, pg 91

⁸⁹ SGN GD3 DD-ECR-12 - Independent Review of Ofgem's DD OE approach.

⁹⁰ SGN-GD3-ECR-20 Economic Insight – Ongoing Efficiency for Gas Networks, Dec 2025

⁹¹ SGN-GD3-DD-ECR-12 Economic Insight - Qualitative Arguments for Lower OE

Section 5 Address manifest inconsistencies in the risk and return package

139 This section covers two broad actions that Ofgem need to take to ensure that the Final Determination is financeable and investable. It is structured as follows:

- In section 5.1, we assess the allowed return (Action 4a) by looking at the technical aspects of how Ofgem have derived its cost of capital proposals, checking these results against a wide range of cross checks and independent consultant reviews. Where required, we put forward our proposals to update the allowed cost of capital.
- In section 5.2, we focus on expected investor returns and the need to ensure an appropriate balance of risk is achieved (Action 4b). Through carrying out detailed risk assessment across all areas of the Draft Determination package, both for GD3 and longer term, we examine whether the package is financeable and investable. We quantify these risks on a workload-adjusted base, downside and upside case and summarise the mitigations required in the Draft Determination to close these risk gaps.

5.1 Provide an appropriate allowed return on capital

140 This section examines the methodology Ofgem has used to determine the proposed allowed cost of equity and debt, further cost of capital evidence available and the cross checks that are available. We also look at the dividend yield assumption and finally the approach to regulatory depreciation.

141 There are significant risk exposures with the longer-term uncertainties associated with the gas transportation sector that are yet to be resolved. The allowed return on capital set out in the Draft Determination is insufficient to reflect the forward-looking costs of raising debt and provide an appropriate return to investors in the RIIO-GD3 period that reflects the unique gas risks in the future.

142 This understatement in the Draft Determination is due to a number of weaknesses in Ofgem's approach, which are covered in more detail in this section with relevant evidence, these are:

- poor benchmarking, for example, Ofgem's sector benchmarking approach on the cost of debt;
- failure to recognise current market evidence, particularly on TMR and pricing cost of carry allowance;
- methodological weaknesses, for example, in determining the comparator asset beta sample and appropriate gas premium for new debt; and
- a lack of comprehensive cross checks, which we believe informs this understatement.

5.1.1 Cost of equity

Determining the CAPM range

143 We consider a cost of equity in the range 6.2% to 7.6% is justified as opposed to the 6.04% proposed in the Draft Determination⁹². Based on the assessment of expected returns (see Section 5.2), a cost of equity above the mid-point of our range will be appropriate, save any mitigations we believe should be made in the Final Determination.

144 On the cost of equity, along with all other GDN's, we commissioned Oxera⁹³, to provide updates to the cost of equity estimates from its RIIO-3 SSMD reports⁹⁴, with further considerations and evidence in response to Ofgem's RIIO-3 DD. The updated approach considers regulatory precedents, developments in capital markets, academic evidence, and the UK Regulators Network (UKRN) cost of capital estimation guidance. The cut-off date for our analysis is 31 March 2025, consistent with Ofgem's RIIO-3 Draft Determination.

145 In recent years, the wider economy has gone through a step-change in capital market and macroeconomic contexts compared with those in which the RIIO-2 price controls were determined. Similarly, gas networks face a significant level of uncertainty about the future of gas, while having to maintain the current operational resilience

⁹² RIIO-3 Draft Determinations – Finance Annex, pg59, table 17

⁹³ SGN-GD3-DD-ECR-19: RIIO-GD>3 cost of equity and debt premium cross-check

⁹⁴ Oxera (2024), 'RIIO-3 cost of equity—CAPM parameters' set out the CoE parameters applicable to all energy networks, before the consideration of sector specific forward-looking risks. Oxera (2024) 'Cost of equity for RIIO-GD3' set out evidence of how to reflect gas specific risks in an appropriate GDN Cost of Equity range, through a revised GDN asset beta allowance.

of the networks. These aspects stress the critical role played by the regulatory allowance in enabling companies to retain existing and attract new capital. Oxera note that in the RIIO-3 Draft Determination Ofgem continues to recognise the importance of ensuring the investability of the energy sector. This was, and remains, the premise for the methodology laid out in Oxera's reports.

146 Whilst we welcome some changes made by Ofgem to ex-ante TMR methodology and the inclusion of a more representative sample of betas incorporating some gas evidence, we do not feel they have gone far enough to apply robust methodology throughout the cost of equity. Specifically, to achieve an investable allowed cost of equity, we consider that Ofgem should:

- account for the convenience premium embedded in government bonds when estimating the risk-free rate;
- inform its TMR range predominantly on the basis of the ex-post TMR;
- reflect the change in the interest rate environment in its TMR estimate, consistent with the previous regulatory decisions, as this is required for investability; and
- set the asset beta range based on gas network comparators or in the upper half of their estimated range to account for forward-looking risks faced by gas networks to reach the government's net zero objectives, which are placing upward pressure on the investability of the sector.

147 Oxera's proposed cost of equity is a range driven by the CAPM parameters, is summarised below.

Table 4: Gas-specific cost of equity range

Formula	Ofgem (RIIO-3 DD)			Oxera (RIIO-GD3)		
	Low	High	Proposed	Low	High	Midpoint
RFR	[A]	2.01%	2.01%	2.01%	2.25%	2.25%
TMR	[B]	6.80%	6.90%	6.90%	7.00%	7.25%
Asset beta	[C]	0.300	0.450	0.375	0.375	0.450
Re-levered equity beta at 60% gearing ⁹⁵	$[D] = \{[C] - (\text{gearing} \times \text{beta debt})\} / (1 - \text{gearing})$	0.64	1.01	0.83	0.83	1.01
CAPM CoE	$[E] = [A] + [D] \times ([B] - [A])$	5.06%	6.96%	6.04%	6.17%	6.84%

Source: Oxera analysis and Ofgem (2025), 'RIIO-3 Draft Determinations – Finance Annex 1 July, Table 17

148 This table proposes a range of 6.2% to 7.6%, with a mid-point of 6.84%, and is further covered in FQ7 – 11 in the finance annex, which shows that on all the key parameters, Ofgem are still falling short of what we, and Oxera, believe to be the appropriate application of CAPM by c. 80bps (mid-point).

Application of equity/investability cross-check

149 Ofgem has stated that it intends to focus on developing an investable price control and that it would use cross-check evidence to support this endeavour. In response, Frontier Economics, on behalf of the sector, prepared a report⁹⁶, setting out how cross-check evidence could be used to assess investability which better supports our cost of equity range rather than Ofgem's.

150 Our response to FQ12 sets out how Ofgem's cross-check review is selective in its treatment of the evidence base. Across the cost of equity and TMR, Ofgem has only considered the following four cross checks:

- MARs (Market-to-Asset Ratios);
- OFTO (Offshore Transmission Owner) bid implied returns;
- Investment Managers' TMR forecasts; and
- Infrastructure Funds' implied cost of equity.

151 The Frontier Economics report sets out, not only do Ofgem's cross checks have their limitations (implying a wider set of cross checks are required), but they would also report higher values if they used more robust assumptions, bringing into question Ofgem's Draft Determination cost of equity point estimate of 6.04%, even before consideration of a wider set of cross checks. For example, Frontier's calculations suggest the MARs and

⁹⁵ The debt beta is assumed to be 0.075. Values may not add up due to rounding

⁹⁶ SGN-GD3-DD-ECR-21: Updated Cost of Equity Cross-Check Evidence

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infrastructure fund implied cost of equity should be 9.6% and 7.3% CPI-H real, compared to Ofgem's 8.5% and 5.2%, respectively.

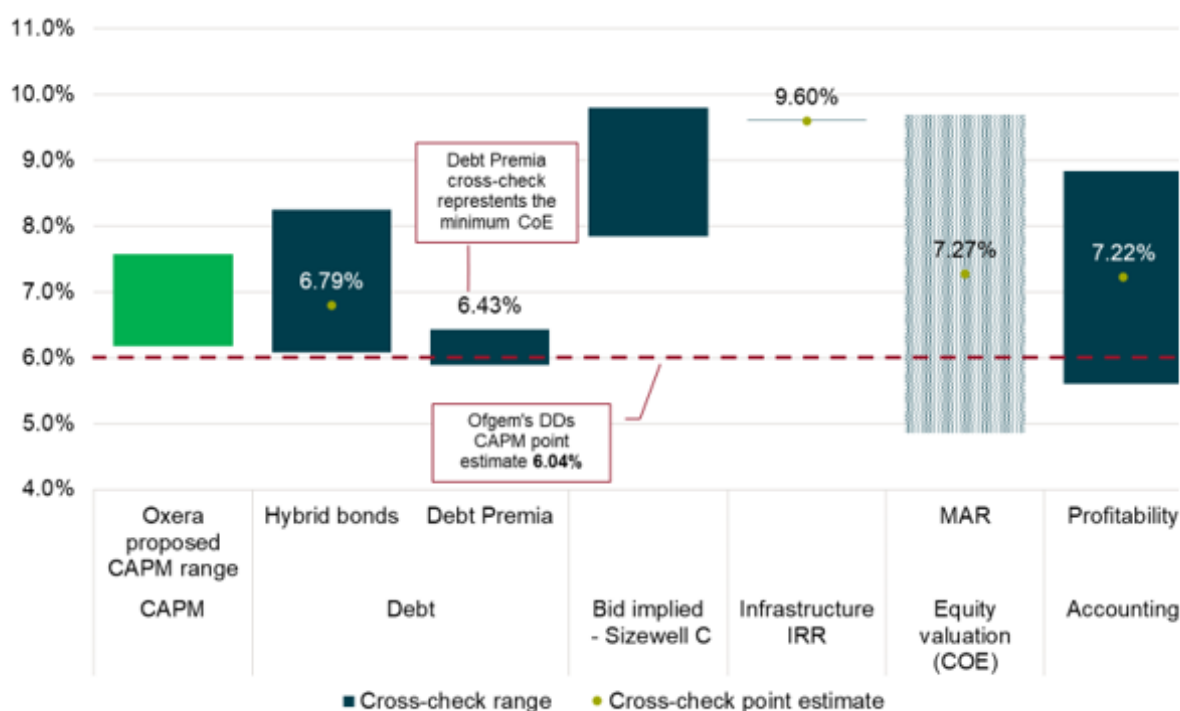
152 Frontier's report highlights the wider set of cross-checks that should be considered, that are robust and well-supported indicators (such as the hybrid bond and calibrated Dividend Growth Model/TMR Glider based cross-checks). These have been ignored by Ofgem on the basis of methodological caveats that could equally apply to other cross-checks which Ofgem uses.

153 Frontier Economics conclude that the approach to deciding which cross-check evidence to rely on, and which to essentially discard, in the Draft Determinations is biased, as it has not appraised the merits of different types of cross-checks on a consistent and objective basis. If Ofgem were to apply a consistent standard of evidence, they should:

- place weight on DGM-based TMR cross-checks, if they continue to assign weight to their MAR inference cross-check; and
- place weight on debt-based cross-checks (such as hybrid bond, ARP/DRP and inference analysis when assessing the overall cost of equity, as the criticisms levied on the hybrid bond cross-check are present in regulators' own cross-checks.

154 By considering a wider range of evidence, Ofgem would be better equipped to set the cost of equity at an appropriate level which mitigates investability risks and protects customers. The results of their cost of equity cross checks are summarised in the figure below.

Figure 11: Cost of equity cross checks



Source: Frontier Economics: Updated Cost of Equity Cross-Check Evidence, SGN-GD3-DD-ECR-21

155 The key message is that almost no cross-check evidence is supportive of Ofgem's Draft Determination cost of equity point estimate of 6.04% as shown by the dotted line. The only exception being the low end of the MAR range. This is not a reasonable basis to support the Draft Determination position when the balance of evidence strongly indicates that a higher CAPM cost of equity output is required to mitigate investability risks.

156 By contrast, the top end of Ofgem's CAPM range (6.96% CPIH-real) and Oxera's CAPM point estimate (6.84).⁹⁷ have much greater overlap with the cross-check evidence. These CoEs, therefore, provide a more credible prospect as an investable proposition.

157 TMR cross-check evidence helps explain why Ofgem's proposed TMR range is too low when compared against an investable value implied by the cross-checks (this is further set out in FQ12).

5.1.2 Cost of debt

158 On cost of debt, we have commissioned NERA (along with other GDNs and GT's) to review the position Ofgem have taken on setting the cost of debt allowances in their following reports;

- SGN-GD3-DD-ECR-17: GDNs & NGT Cost of Debt at RIIO-3; and
- SGN-GD3-DD-ECR-18: Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3.

159 In the DD, Ofgem have set a nominal allowance of 5.07%.⁹⁸ but we believe this should be 45bps higher by:

- improving the sector benchmarking approach taken by Ofgem by applying a simple GDN average as opposed to a debt weighted average, which puts too much emphasis on Cadent (15bps);
- appropriately tenor adjusting the gas premium on new debt (5bps);
- applying the correct level of additional borrowing cost allowances, primarily cost of carry (19bps); and
- reinstatement of the infrequent issuer allowance as per RIIO2 which has been erroneously removed (6bps).

Sector Benchmarking and Gas Premium (20bps adjustment proposal)

160 Overall, there have been some positive methodology changes by Ofgem, such as recognising a specific gas sector cost of debt calibration, given the different cost of debt that is clearly emerging between the gas and electric sectors.

161 However, due to the lack of comparable data points in the gas cohort (only five company data points, of which Cadent has a very large weighting on the sector), the gas sector average cost of debt needs to be carefully calibrated.

Indeed, we believe SGN's cost of debt (excluding additional borrowing and infrequent issuer costs) will be 20bps above Ofgem's cost of debt allowance and therefore materially exposed due to the unrepresentative benchmark and incorrect assessment of gas premium, not through inefficiency. However, this can be largely mitigated by firstly:

- taking a simple average, rather than a debt-weighted average. This counteracts the undue weighting currently applied to Cadent and will increase the current calculated sector average by 6bps; and
- removing National Gas Transmission from the GDNs average sector cost of debt. Given our expectation that NGT has less uncertainty around the impact of the Future of Gas, as reflected in Ofgem's different approach to accelerated depreciation for GT. This correction will increase the sector average by 9bps.

162 Given the significant weaknesses regarding the accuracy of Ofgem's sector average, we believe an adjustment of 15bps is justified by the rationale set out above.

163 Secondly, while we welcome the proposal of a gas sector benchmark adjustment to recognise a gas premium on new debt, the 25bps calculated by Ofgem understates the premium, and the Draft Determinations have not provided clear and transparent reason for doing so.

164 Ofgem have incorrectly not adjusted for tenor. We believe the gas premium must be tenor adjusted, such that the notional company is fully funded for the return required by debt investors to invest in gas on the investment horizon implicit in the A/BBB index (and that used in the CAPM cost of equity calculation), on a consistent basis. In addition, gas networks' choice of debt tenors (contrary to Ofgem's statement at para. 2.23 of the Finance Annex) is not discretionary, given the reluctance of investors to invest much beyond 10 years. When controlling

⁹⁷ SGN-GD3-DD-ECR-19 – Oxera - RIIO-GD>3 cost of equity and debt premium cross-check, pg8

⁹⁸ RIIO-3 Draft Determinations - Finance Annex, pg15, table 3

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for tenor, this suggests a benchmark adjustment of c. 45bps. This would add 5bps on to the allowed cost of debt allowance.

165 There also needs to be an 'ex-post true up' of the allowed gas premium, due to the uncertainty of how this premium could evolve over the next 5 years. Alternatively, scenarios of how the gas premium could evolve should be included in the calibration analysis, along with Totex and interest rates scenarios, and thus accounted for in the headroom for the gas sector (which we note currently is significantly below the 39bps afforded to the Electricity Transmission sector).

Additional borrowing costs

166 NERA's estimate additional borrowing costs of 44bps, which is 19bps higher than Ofgem's Draft Determination of 25 bps. This is summarised in the table below and supporting evidence.⁹⁹.

Table 5: Summary of additional borrowing cost proposal

Units: bps p.a	NERA	Ofgem	NERA	
	(March 2024 GDNs)	RIIO3 DD	(Aug 2025, exc Gas network premium LOW)	(Aug 2025, exc. Gas network premium HIGH)
Transaction costs	8.5	7	8	8
Liquidity cost and cost of carry	13+12-27 (19)	15	5+26	5+26
CPIH premium	18-23 (21)	3	3	6
Additional cost of borrowing	57-77 (67)	25	43	45
Small company/infrequent issuer	10-18 (14)	0	3.5	9
Total	67-95 (81)	25	46.5	54

Source: NERA analysis

167 The primary driver for the increase compared to Ofgem is our view on liquidity and cost of carry changes where requirements to hold liquidity and the cost of holding this liquidity have been significantly understated by Ofgem. They have used a backward-looking assessment of cost of carry margin over the past 5 years, which is not representative of either the longer-term history, current margins or forecast margins, which all point to a higher cost.

168 More details can be found in the detailed answers to the Cost of Debt consultation questions in the Finance Annex response, in particular FQ1 and FQ4.

Infrequent Issuer Costs

169 We disagree with the removal of the infrequent issuer allowance. Ofgem does not include the infrequent issuer allowance as it considers this has been compensated by its estimate of the gas network premium of 25bps. However, as only 57% of the issuance contained in this estimate was from Networks that Ofgem recognise as infrequent issuers, this assumption is incorrect. Additionally, evidence from the cost of swap mitigations also informs the range for this area. This supports an infrequent issuer premium of between 3.5bps and 9bps with a mid-point of 6bps.

5.1.3 Overall cost of debt proposal

170 Putting all this together, we are proposing a cost of debt allowance of 5.52% nominal, compared to Ofgem's 5.07%. which is summarised in the table below.

⁹⁹ SGN-GD3-DD-ECR-18 - Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3

Table 6: Summary of proposed cost of debt allowances

	Draft Determination	SGN Proposal	Evidence of movement
Embedded debt	4.28%	4.30%	Based on inaccuracies in sector benchmarking (See FQ1) NERA market analysis (see FQ1)
New debt	6.06%	6.07%	
Gas premium	0.25%	0.45%	
Total new debt	6.31%	6.52%	
Weighting of new debt	23%	28%	
Allowed CoD	4.76%	4.93%	
Headroom	0.06%	0.09%	
Total Cost of Debt (pre ABC)	4.82%	5.02%	
Additional borrowing cost	0.25%	0.44%	NERA analysis of ABC's (see FQ4)
Infrequent issuer premium	0.00%	0.06%	See FQ6
Overall allowed cost of debt (nominal company)	5.07%	5.52%	

Source: SGN analysis

171 The proposed figures above are consistent with NERA's two reports, and the 5.52% sits at the conservative end of the 1% and 2% interest rate sensitivity for a GDN simple average benchmarking approach. Further detail of our cost of debt allowance position is covered in FQ1–6 in the Finance annex

172 Finally, due to the future uncertainty of the level of gas premium in GD3, we continue to propose an uncertainty mechanism to true up / down for the actual observed premium in GD3. We disagree with Ofgem that this figure cannot be accurately determined.

5.1.4 Overall cost of capital proposal

173 Combining our cost of equity and cost of debt proposals from this section, the overall cost of capital position is summarised in the table below.

Table 7: SGN proposed WACC in Final Determination

	DD Proposal	SGN Proposal	Evidence for Movement
RFR	2.01%	2.25%	Oxera / KPMG analysis for convenience yield (See FQ7 Finance Annex)
Debt Beta	0.075	0.075	
Asset Beta	0.375	0.413	Inclusion of US betas in high end of range and Euro reg precedents (See FQ10, FQ11 Finance Annex)
Notional Gearing	60%	60%	
Equity Beta	0.83	0.92	
TMR	6.90%	7.25%	More weight on historical ex-post and reflection of current high interest rates (See FQ9 Finance Annex)
Cost of Equity (post tax)	6.04%	6.84%	FEN Oxera report
Aiming Up	0.0%		Frontier Cross Checks and KPMG Balance of Risk Analysis (See FQ12, FQ16 Finance Annex)
Cost of Equity inc Aiming Up (Real)	6.04%	6.84%	
Embedded Debt	4.28%	4.30%	Based on inaccuracies in sector benchmarking (See FQ1) NERA market analysis (See FQ1)
New Debt	6.06%	6.07%	
Gas premium	0.25%	0.45%	
Total New Debt	6.31%	6.52%	
Weighting of new debt	23%	28%	
Allowed CoD	4.76%	4.93%	
Headroom	0.06%	0.09%	

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Total Cost of Debt (pre ABC)	4.82%	5.02%	
Additional Borrowing Costs (ABC)	0.25%	0.44%	NERA analysis of ABC's (See FQ4)
Infrequent Issuer Premium	0.00%	0.06%	See FQ6
Overall Allowed Cost of Debt (nominal)	5.07%	5.52%	
Cost of Capital (real)	4.22%	4.80%	
Cost of Capital (Semi Nominal)	5.09%	5.64%	

Source: SGN analysis

174 This shows a semi-nominal cost of capital point estimate of 5.64% compared with Ofgem's 5.09%. This is a minimum figure, the level of increase from this mid-point will depend on the risk mitigation proposed in this response being implemented in the final determination, as quantified in our balance of risk assessment..

5.1.5 Dividend yield

175 The 3% dividend yield assumption (excluding accelerated return of capital) is not appropriately calibrated for a network that no longer has genuine potential for asset growth and needs to be more closely aligned with the cost of equity (which we consider should be higher than 6%).

176 The assumption of a 3% dividend yield fundamentally undermines Ofgem's notional company financeability assessment and damages Investor perception. It implies that investors can only earn half the allowed return with no prospect of capital growth, by definition, this essentially traps equity for the longer term. This is further covered by FQ14 and Oxera's report¹⁰⁰.

5.1.6 Accelerated depreciation and wider regulatory framework review

177 Ofgem has proposed the application of Accelerated Depreciation Option 4 on assets added to the RAV in GD3. However, this proposal does not meet current needs for RIIO-3 nor the objectives set by Ofgem itself as it fails:

- On its own to significantly reduce the risk of asset stranding and provide confidence on full RAV or cost recovery for investors;
- Provide protection for customers from long-term bill increases;
- To have been demonstrated to be in the interests of, or fairer to, customers (today's and future customers); and
- Does not set out a path for the changes in the regulatory framework needed when the RAV declines relative to the ongoing costs of the network.

178 In addition, the proposal has failed to be the subject of a proper Impact Assessment, including that committed to by Ofgem as part of its Impact Assessment at SSMD. The Ofgem proposal:

- Results in higher costs for customers today (£8 p.a.) at a time when the pathway and trajectory of customer numbers remains uncertain;
- Will result in higher overall costs in the longer-term as the continued uncertainty increases the cost of capital;
- Is not grounded in robust logic as to why accelerated depreciation is needed; and
- Is counterintuitive in terms of the treatment of new assets and those developed over the last decade.

179 It is important, therefore, for the Final Determination that Ofgem:

- Sets out clear unambiguous statements, as the economic regulator for the sector, that it assumes and has assumed that the RAV and efficient incurred expenditure will be fully recoverable in fulfilling its financeability duty;

¹⁰⁰ SGN-GD3-DD-ECR-25: Dividends in RIIO-GD/T3

- Provides protection over customer bills, particularly for those in vulnerable circumstances, through making it clear that the full recovery of RAV and costs cannot be borne by gas customers alone, if there is transition to alternative heating sources by 2050;
- Sets out the need for changes to the economic framework should network utilisation or customer numbers fall, for example, to provide an appropriate equity buffer; and
- Undertakes a comprehensive Impact Assessment, in line with the requirements set out in the Utilities Act, 2000, before introducing any policy changes.

180

5.2 Providing a package with an appropriate balance of risk

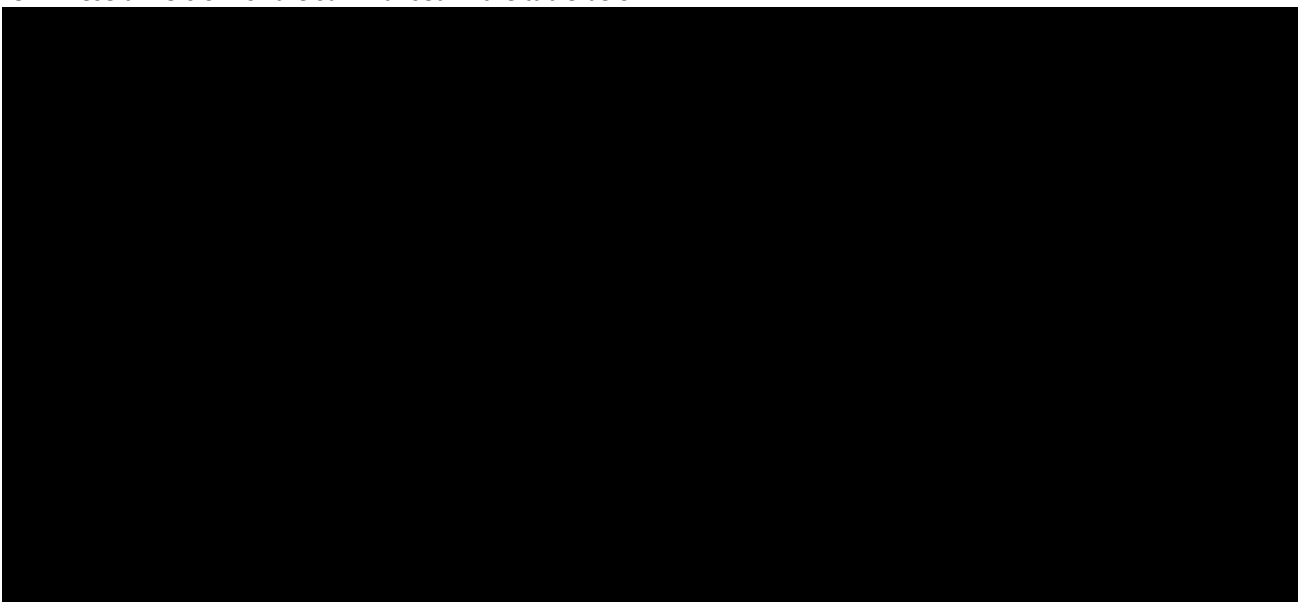
181 Our analysis, in conjunction with KPMG¹⁰¹, demonstrates there is a requirement to rebalance the risk and return by addressing the Totex and cost of debt funding gaps, which are reducing the workload-adjusted base case expected return on equity by [REDACTED] through the mitigations put forward in our Draft Determination response.

182 We have also considered longer-term drivers of risk, such as the impact shortening tenors on new debt are having on refinancing risk, as well as the risks of asset stranding, which are highly material. This signals an investability issue than needs to be addressed with credible and urgent measures beyond Ofgem's vires which need to be taken outside of the RIIO framework with the Government, including assurances on the surety of RAV recovery.

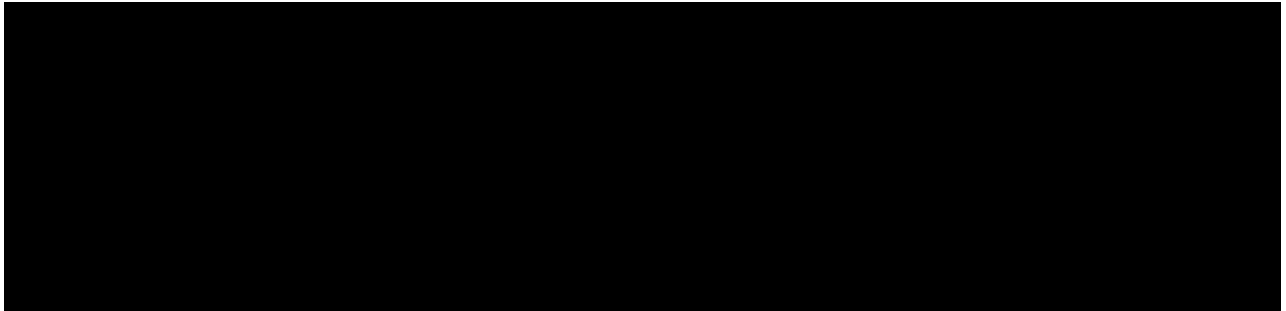
183 Price controls need to provide an appropriate balance of risk in the immediate price control period and beyond to ensure it is a 'fair bet' otherwise uninvestable returns and weakened credit metrics will risk the ability to retain existing equity, increase financing costs and ultimately drive up the cost of capital and bills, which is not in the consumer's interest. As it stands, the Draft Determination does not provide for an efficiently operated SGN to be able to come close to earning the allowed return, which we believe should be 6.84% due to the following risks which will all be borne by investors:

- The understatement of safety-related workload (Action 1);
- the underfunding of the efficient cost of delivery (Action 2 & 3);
- the underfunding of financing costs (Action 4); and
- the ability to recover costs in the longer term (Action 4).

184 These drivers of risk are summarised in the table below.



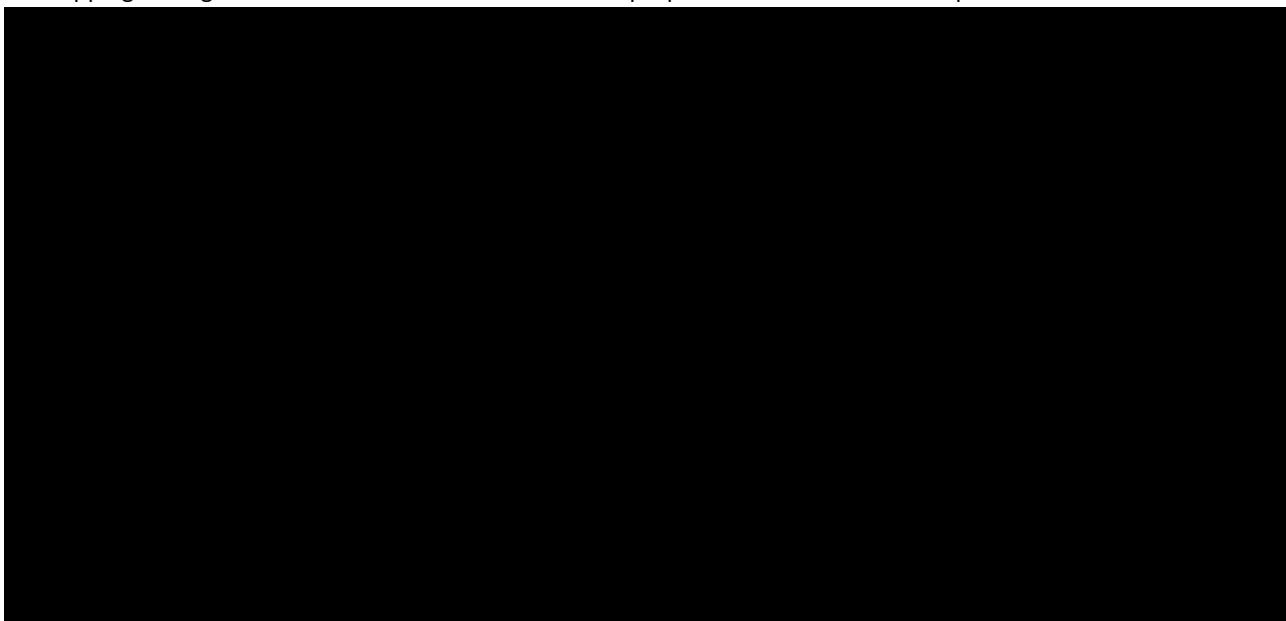
¹⁰¹ SGN-GD3-DD-ECR-10 KPMG - GD3 Risk Analysis



Source: KPMG Risk Analysis (SGN-GD3-DD-ECR-10)

185 The Draft Determination as it stands contains significant asymmetric downside risks that need to be addressed at source by taking the actions we've identified, shown in the table below. If any risks remain unmitigated, this will need to be reflected in the cost of equity to reflect the remaining risk borne by investors.

186 The figure below compares the expected RoRE range for risk exposure for Scotland and Southern Networks stepping through from the Draft Determination to our proposals as set out in this response.



187 The figure above shows that the actions we have identified to address the drivers of risk would leave a much smaller residual base case risk. However, this analysis focuses only on risk within the RIIO-GD3 period. Investors are exposed to a long-term risk of asset stranding (not recovering RAV or efficient costs) which adds a further [REDACTED] downside exposure to the figures above.

188 Ofgem have a duty to ensure that networks can finance their licenced activities. In discharging this duty, Ofgem should consider relevant factors on certain key parameters/drivers. Ofgem should also ensure the Draft Determination has the stated effect of attracting investors and set a fair return which will ultimately minimise costs to consumers in the future (see section 1.4 of the Finance Annex).

189 The Draft Determination has not been subject to a thorough financeability assessment, risk assessment or impact assessment therefore, Ofgem have no basis to conclude the Draft Determination is financeable. [REDACTED] [REDACTED] absent the required changes set out in this response). In particular:

- appropriate consideration has not been given to longer-term financeability and the attendant risks;
- a full and proper impact assessment has not been conducted on each of SGN's regulated licensees as is required under the Utilities Act;
- actions explicitly stated at SSMD to complete impact / risk assessments have not been carried out, such as a review of the impacts of declining demand scenarios on consumers and investors;

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- no consideration has been given to risk analysis by reference to expected performance for each of SGN's licensees and instead only stylised and non-evidenced Totex risk exposure has been considered; and
- key risks concerning financing exposure for a notionally efficient licensee have not been fully considered, without evidence that the financing of any individual licensee is inefficient.

190

191 The risk analysis can also support the financeability assessment of the Draft Determinations, by informing the design of appropriate scenarios to test whether the notional company can expect to achieve the target credit rating and is able to withstand plausible downside risks by maintaining an appropriate credit rating. Ofgem should take this analysis into account, which would address a flaw in Ofgem's Draft Determinations, whose financeability testing is based on illustrative scenarios that are not representative of likely expected and downside performance outcomes in GD3. We believe this will clearly show the need for Ofgem to address the downside asymmetry at source in the FD.

192

193 Recent actions by S&P and Moody's highlight the uncertainty and show how this is impacting risk perceptions. Indeed, S&P have already signalled the removal of the low-risk status afforded to gas and consequently tightened their range by one notch making it very difficult to maintain BBB+ in the future, even at neutral performance. Absent mitigation/certainty, there is always a risk of further rating agency action in the future; therefore, the financeability assessment in the longer-term needs to be considered in that light.

194

Ofgem has acknowledge the importance of stability long-term, see Finance Annex 5.14). This is because:

- as a result of the historical and continued revenue restriction placed upon the licensee by Ofgem, in the context of the discharge of its duties and the importance of affordability of bills to customers, the licensee has been prohibited from seeking to recover the capital it has invested and continues to invest in the RAV outside of the depreciation profile put in place by Ofgem;
- it does so without surety from Ofgem that the RAV is in fact recoverable in full – in fact Ofgem explicitly suggests in its proposals on Accelerated Depreciation that there is a risk of asset stranding;
- for Ofgem to have come to any assessment that the arrangements were financeable Ofgem must have been operating on the assumption that the RAV is recoverable in full;
- there needs to be a basis for this assumption – yet no basis is given, nor is it explicitly stated (indeed some of the statements previously stated at SSMD are no longer present) – despite the best practice regulatory transparency principle; and
- Investors need to consider the licence modifications and revenue restrictions being placed upon them in perpetuity. There is no certainty or guarantee that they will somehow be amended in the future.

195 Considering the longer term, our analysis also considers further drivers of risk with an impact in GD3 but arising from longer-term issues, such as shortening tenors on new debt that increase debt maturity concentrations and exposure to future interest rate volatility at refinancing, as well as the risks of asset stranding. The asset stranding

¹⁰² RII0-3 Draft Determinations - Finance Annex, para 9.20

risk has been assessed by constraining revenue recovery by an affordable bill cap and then running scenarios based on FES customer pathways. While maturity concentration risk could be addressed via the new cost of debt allowance, the magnitude of the estimated RoRE impact from stranding signals an investability issue that needs to be addressed with credible and urgent measures taken outside of the RIIO framework.

196

197 The fuller assessment of the KPMG Balance of risk analysis¹⁰³, including the assumptions and methodologies underpinning this analysis can be found in response to FQ17 in the finance annex of this submission.

198 Further details of our position on the areas covered in section 5, and further topics such as financial resilience, debt financeability, corporation tax, return adjustment mechanisms, RAV indexation and other Finance issues – are to be found in our responses to the DD Finance FQs.

Section 6 Conclusion

199 Our GD3 Business Plan recognises the significant challenge of determining the appropriate level of investment in the energy network at a time of such uncertainty over the long-term role of gas and mounting pressures on customer bills. The removal of £1 billion of essential investment at Draft Determination means our plan is not deliverable

200 We only included the investment that was necessary to maintain safety and keep bills affordable. The removal of safety-critical workload and the efficient cost allowances needed to deliver it will compromise the service we provide to customers and our efforts to reduce emissions from our network.

201 The Draft Determination also creates a significant asymmetric risk both in the short and long-term. Short-term risks must be mitigated at source, and we have presented four actions that will ensure the Final Determination is appropriately balanced. These are:

- (a) Action 1 – Restore all safety-critical workload;
- (b) Action 2 – Correct the suite of errors in Repex unit costs;
- (c) Action 3 – Correct allowances to reflect operational reality; and
- (d) Action 4 – Address manifest inconsistencies in the risk and return package.

202 The Final Determination must be grounded in reality. The evidence currently shows that investment in the gas network must be maintained throughout GD3 and beyond so it can continue to operate safely and resiliently. The evidence also shows that the cost of delivering critical investment is significantly higher in our Southern network than in Scotland and the north. These factors must be recognised and reflected in our price control settlement to avoid underinvestment, erosion of performance and public trust and future price increases.

203 The Final Determination must also consider the increased uncertainty with respect to the role and long-term investability of gas distribution (relevant to both debt and equity investors) and the unprecedented demand and competition for a finite pool of supply chain resources, because of the scale of infrastructure investment in other sectors. These factors, coupled with the overall volatility of the macroeconomic environment (e.g. high interest rates), have increased the perception of risk associated with investing in the gas network.

204 Failure to address these risks will undermine investor confidence and increase customer bills in the longer term. Action must be taken to ensure the Final Determination enables us to maintain a safe network, deliver for customers and attract the right investors to the UK's energy sector. We need a clear statement to investors that the investment they have made, will make over the coming years and in the future to maintain the safe and reliable operation of the network will be fully recoverable.

¹⁰³ SGN-GD3-DD-ECR-26: RIIO GD3 Draft Determinations – Risk analysis for a notional GDN

Section 7 Supporting evidence

205 In the table below, we have provided details of all the consultation response documents and supporting evidence that has been submitted to Ofgem in addition to the evidence that we provided in support of our Business Plan.

Title	Unique Reference
<i>SGN Draft Determination response overview</i>	<i>SGN-GD3-DD-OD</i>
<i>Overview Question Responses (OVQ)</i>	<i>SGN-GD3-DD-OVQ</i>
<i>SGN Question Responses (SGNQ)</i>	<i>SGN-GD3-DD-SGN</i>
<i>GDN Question Responses (GDQ)</i>	<i>SGN-GD3-DD-GD</i>
<i>Finance Question Responses (FQ)</i>	<i>SGN-GD3-DD-FIN</i>
SGN supporting evidence	
<i>Appendix 1 - Advanced Leakage Detection engineering response</i>	<i>SGN-GD3-DD-ENG-SD001</i>
<i>Appendix 2 - Steel Services operating above 75mbar</i>	<i>SGN-GD3-DD-ENG-SD002</i>
<i>Appendix 3 - Overbuilds</i>	<i>SGN-GD3-DD-ENG-SD003</i>
<i>Appendix 4 - Multi-Occupancy Buildings</i>	<i>SGN-GD3-DD-ENG-SD004</i>
<i>Appendix 5 - General Reinforcement</i>	<i>SGN-GD3-DD-ENG-SD005</i>
<i>Appendix 6 - Intelligent Gas Grid (IGG) Strategy</i>	<i>SGN-GD3-DD-ENG-SD006</i>
<i>Appendix 7 - River and Coastal Erosion</i>	<i>SGN-GD3-DD-ENG-SD007</i>
<i>Appendix 8 - Pressure Management Maintenance</i>	<i>SGN-GD3-DD-ENG-SD008</i>
<i>Appendix 9 - Functional Safety</i>	<i>SGN-GD3-DD-ENG-SD009</i>
<i>Appendix 10 - Local Gas Treatment</i>	<i>SGN-GD3-DD-ENG-SD010</i>
<i>Appendix 11 - Governors Other</i>	<i>SGN-GD3-DD-ENG-SD011</i>
<i>Appendix 12 - Network Integrity</i>	<i>SGN-GD3-DD-ENG-SD012</i>
<i>Appendix 13 - R6 Governors</i>	<i>SGN-GD3-DD-ENG-SD013</i>
<i>Appendix 14 - Preheating Replacement Programme</i>	<i>SGN-GD3-DD-ENG-SD014</i>
<i>Appendix 15 - Bulk Service Replacement</i>	<i>SGN-GD3-DD-ENG-SD015</i>
<i>Appendix 16 - Cams Hall EJP resubmission</i>	<i>SGN-GD3-DD-ENG-SD016</i>
<i>Appendix 17 - Other Distribution Mains and Services</i>	<i>SGN-GD3-DD-ENG-SD017</i>
<i>Appendix 18 - Wick and Thurso SIU- Compressed Biomethane (CNG)</i>	<i>SGN-GD3-DD-ENG-SD018</i>
<i>Revised South London MP CBA</i>	<i>SGN-GD3-DD-ENG-SD019</i>
<i>118ABO81-7 SGN RRM Final Report_RiskScoreAppendix</i>	<i>SGN-GD3-DD-ENG-SD020</i>
<i>DD_MOBs_Data Requests</i>	<i>SGN-GD3-DD-ENG-SD021</i>
<i>SGN RRM_Summary of Models</i>	<i>SGN-GD3-DD-ENG-SD022</i>
<i>SGN Thresholds Update 2024 10528306_v2 (final issue)</i>	<i>SGN-GD3-DD-ENG-SD023</i>
<i>SGN_GD3_BDPT_CV6.09_Risers</i>	<i>SGN-GD3-DD-ENG-SD024</i>
<i>SGN_RRM_20250709_v2_Potential Interventions</i>	<i>SGN-GD3-DD-ENG-SD025</i>
<i>R6 Justification V1 1</i>	<i>SGN-GD3-DD-ENG-SD026</i>
<i>Stubs</i>	<i>SGN-GD3-DD-ENG-SD027</i>
External supporting evidence	
<i>Economic Insight - Regional contractor costs</i>	<i>SGN-GD3-DD-ECR-01</i>
<i>Deecon - REPEX Cost Validation - MOBs & Risers</i>	<i>SGN-GD3-DD-ECR-03</i>
<i>Deecon - REPEX Productivity Assessment Survey</i>	<i>SGN-GD3-DD-ECR-04</i>
<i>Deecon - REPEX Mains Lay Cost Modelling Report</i>	<i>SGN-GD3-DD-ECR-05</i>
<i>Deecon - Cost Validation Streetworks Report</i>	<i>SGN-GD3-DD-ECR-06</i>
<i>Frontier Economics - Cost of Equity cross-check report</i>	<i>SGN-GD3-DD-ECR-08</i>
<i>KPMG - GD3 Risk Analysis</i>	<i>SGN-GD3-DD-ECR-10</i>
<i>IGEM Future Energy Networks - Improving Ofgem's assessment of the systematic risk of gas networks</i>	<i>SGN-GD3-DD-ECR-11</i>
<i>Independent review of Ofgem's DD OE approach</i>	<i>SGN-GD3-DD-ECR-12</i>
<i>Review of the gas premiums</i>	<i>SGN-GD3-DD-ECR-13</i>
<i>DNV - Cams Hall DNV Supplementary Report</i>	<i>SGN-GD3-DD-ECR-16</i>

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<i>NERA - GDNs & NGT Cost of Debt at RIIIO-3</i>	<i>SGN-GD3-DD-ECR-17</i>
<i>NERA - Gas Network Premium (GNP) and Additional Cost of Borrowing (ACB) for GD/GT3</i>	<i>SGN-GD3-DD-ECR-18</i>
<i>Oxera - RIIIO-GD&GT3 cost of equity and debt premium cross-check</i>	<i>SGN-GD3-DD-ECR-19</i>
<i>KPMG - Estimating the risk-free rate for RIIIO-3</i>	<i>SGN-GD3-DD-ECR-20</i>
<i>Frontier Economics - Updated Cost of Equity Cross-Check Evidence</i>	<i>SGN-GD3-DD-ECR-21</i>
<i>Frontier Economics - Cross-Check Standards of Evidence</i>	<i>SGN-GD3-DD-ECR-22</i>
<i>KPMG - Inference analysis as a cross-check on allowed returns at GD&T3</i>	<i>SGN-GD3-DD-ECR-23</i>
<i>Kairos - Cost of Equity for RIIIO-3: Gas Vs Electricity and MFM Cross-Check</i>	<i>SGN-GD3-DD-ECR-24</i>
<i>Oxera - Dividends in RIIIO-GD/T3</i>	<i>SGN-GD3-DD-ECR-25</i>
<i>KPMG - RIIIO GD3 Draft Determinations – Risk analysis for a notional GDN</i>	<i>SGN-GD3-DD-ECR-26</i>
Additional technical papers and responses	
<i>GD3 DD Model Changes Technical Guidance</i>	<i>SGN-GD3-DD-TechSupp-01</i>
<i>Assessment of Contractor Premia</i>	<i>SGN-GD3-DD-TechSupp-02</i>
<i>Covering Letter - Cyber</i>	<i>SGN-GD3-DD-CYB-Cover</i>
<i>Cyber DD Response - All CRIDS</i>	<i>SGN-GD3-DD-CYB-ALL-CRIDS</i>