

Citizens Advice response to the Ofgem Call for Evidence on the Electricity Transmission, Gas Transmission and Gas Distribution Business Plans for RIIO-3

Citizens Advice
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Contents

Contents.....	1
Executive summary.....	3
Total Expenditure (Totex) assessment.....	3
Business Plan Incentive.....	5
Customer bill impact.....	6
Financial considerations.....	6
Innovation.....	8
Vulnerability.....	8
Independent Stakeholder Groups (ISGs).....	9
Sector Specific Issues.....	9
Gas Transmission (NGT).....	9
Electricity Transmission.....	10
Gas Distribution.....	11
Total Expenditure (Totex) assessment.....	13
Gas Distribution.....	13
Cadent.....	13
NGN.....	15
SGN.....	17
WWU.....	20
Gas Transmission.....	24
Electricity Transmission.....	26
Totex and Uncertainty Mechanisms.....	26
SHET.....	27
SPT.....	28
National Grid Transmission.....	29
Business Plan incentive.....	34
Customer bill impact.....	36
Financial considerations.....	37
Regulatory depreciation in gas networks.....	37
Investor returns – Cost of Equity.....	39
Innovation.....	47
Level of information provided.....	47
Transparency.....	48

Centering customers.....	48
Vulnerability.....	49
Independent Stakeholder Groups statements.....	50
Sector Specific Issues.....	51
Gas Transmission (NGT).....	51
Incentives.....	51
Electricity Transmission.....	53
Community benefits.....	53
Stakeholder and customer engagement.....	55
Gas Distribution.....	55
Customer service.....	55
Unplanned interruptions.....	55
Disconnections.....	55
Hydrogen.....	56
Our conclusions and recommendations for Ofgem.....	59
Totex assessment.....	59
Gas distribution.....	59
Gas transmission.....	61
Electricity transmission.....	62
Business Plan incentive.....	64
Recommendation.....	64
Customer bill impact.....	64
Recommendation.....	64
Financial considerations.....	65
Regulatory depreciation.....	65
Cost of equity.....	65
Innovation.....	66
Vulnerability.....	67
ISG Statements.....	67
Sector specific issues.....	68
Gas Transmission.....	68
Electricity Transmission.....	69
Gas Distribution.....	69

Executive summary

Citizens Advice welcomes the opportunity to respond to Ofgem's RII03 Framework Consultation. We are responding in our role as the statutory consumer advocate for energy and have focused our response on topic areas where we can add most value. Also, given the volume of material to consider, we have primarily focussed upon the information presented within the main Business Plans. We believe this aligns to Ofgem's intention that the main Business Plan documents should contain sufficient levels of information and evidence on which to draw conclusions.

In this document, we have referred to the energy networks as follows:

NGET - National Grid Electricity Transmission

SHET - Scottish Hydro-Electric Transmission

SPT - Scottish Power Transmission

NGT - National Gas

NTS - National Transmission System

Cadent

NGN - Northern Gas Networks

SGN - Scotia Gas Networks

WWU - Wales and West Utilities

In this section, we have highlighted the key themes of our report. These represent areas with the highest potential consumer impacts where we believe Ofgem should take action.

Total Expenditure (Totex) assessment

The companies have submitted Business Plans for RII0-3 which include significant increases in totex. The following table sets out the proposed increases. Across the three sectors, baseline expenditure for the 5 years of RII0-3 is proposed to increase from £40 billion to £58 billion, an increase of 44%. The additional expenditure for uncertainty mechanisms is £42 billion, bringing

the total potential increase in totex to £66 billion, an increase of 163% on RIIO-2. It is important to highlight here that almost all of this additional cost is in Electricity Transmission.

Table 1: RIIO-3 totex proposals compared to RIIO-2.

Totex (£m 2023/24 prices)	RIIO-2 Allowance	RIIO-3 Baseline	Uncertainty mechanism	RIIO-3 Total	% increase RIIO-2 to 3
Gas Distribution	13678	16304	n/a	16304	19%
Gas Transmission	3220	3940	1313	5253	63%
Electricity Transmission	23633	37947	40976	85247	261%
Total	40531	58191	42289	106804	164%

Track record: we have examined the current progress of companies in delivering against their RIIO-2 allowances. Most companies are underspending their allowances - the transmission sector is underspending by 21%. However, this underspend reduces towards the end of the price control period as companies can make adjustments to defer the expenditure to later years. But it is unclear whether companies have included this carry over in their RIIO-3 bids.

Gas distribution companies have sought an increase of 19%, largely due to more costly iron main replacement work. We are concerned that higher cost work has been deferred from prior price controls and gas companies have already benefited from doing cheaper work first. Customers should not be paying again for these costs. National Gas Transmission has sought an increase of 63% in totex (including uncertainty mechanisms), largely for asset health reasons.

All the gas network companies are seeking substantial increases in totex allowances. We don't think these substantial increases can be justified in a sustained period of declining consumer gas demand, and a reducing number of gas-fired power stations, trends that are forecast to continue.

Electricity transmission companies are proposing a dramatic increase in totex, potentially a four fold increase from RIIO-T2. While an increase in load related expenditure is clearly needed to meet Clean Power 2030 targets, we have concerns about the transparency of information and the justifications that have been provided for both load and non-load expenditure. Also, we note that these plans have been developed in advance of the Government's Clean Power 2030 plan and the forthcoming NESO spatial plan, which may cause further increases.

Across all business plans, there seems to be a limited focus on efficiency. Companies that have proposed ongoing efficiency targets have targeted 0.5% per annum, which we consider to be unambitious and below RIIO-2 levels.

Greater use is proposed for uncertainty mechanisms in RIIO-3 for expenditure that is outside company control, especially major transmission reinforcement projects. While we agree that uncertainty mechanisms also protect consumers from overly generous ex-ante allowances, we are concerned that uncertainty mechanisms that effectively allow companies to pass through costs means that consumers will face additional cost. We consider this transfer of risk should result in a lower allowed company returns.

The RIIO-2 track record to date highlights that most companies are underspending their allowances with many deferring allowances to later years and probably into RIIO-3. We think this raises wider questions about whether the companies can deliver the required investment plans in a cost effective way that will support Clean Power 2030 and the medium-term delivery of net zero.

Business Plan Incentive

For RIIO-3, Ofgem is again using a Business Plan Incentive (BPI), which consists of three stages. Our views on each of these BPI stages are as follows:

Stage A – Transparency: We have observed significant differences in the granularity of information that each network company has published. For example, most companies have not published their Business Plan data tables of financial models which allow more detailed independent analysis and comparison of their Business Plan forecasts. Furthermore, most companies have not published details of their asset health (NARM) forecasts which should justify non-load expenditure claims.

We do not think the level of information in some main Business Plan documents is sufficient in order to reach informed decisions. We believe this is contrary to Ofgem's aims and expectations on companies.

Stages B and C: For stage B, we have outlined our concerns on cost efficiency. For stage C, we would reiterate our comments for stage A.

Customer bill impact

Each of the company plans included information on the impact their plans will make on customer bills. Customer bills will be impacted by a range of factors including totex increases, rates of return and changes to depreciation policy. The headline impacts stated in each plan are:

- NGET forecast that the transmission element of customer bills will increase from £23 in 2026 to £44 in 2031, an increase of £21
- SHET forecast that the transmission element will increase from £45-50 today to £110-£130 per consumer per year by the early to mid 2030's
- SPT forecast that their costs will add an average £6.47 to customer bills over the ET3 period.
- NGT forecast that their gas transmission plan will add £1.34 to customer bills
- Cadent forecast that gas distribution costs will increase from £157 to £214, an increase of £57.
- NGN forecast an increase from £170 to £209, an increase of £39.
- SGN forecast an increase from £150 to £240, an increase of £90.
- WWU forecast an increase from £153 to £244, an increase of £91.

There are significant differences between these forecasts, apparently because different calculation approaches and assumptions have been used. We ask Ofgem to ensure that there is a clear explanation and strong justification for any increases in customer bills.

Financial considerations

In this section we reviewed the Business Plan submissions on financial issues. We focus primarily on two issues, (1) the regulatory depreciation of gas networks and (2) the Cost of Equity (CoE).

- **Regulatory depreciation in gas networks:** The gas network companies generally seek to argue for longer depreciation periods based on an expectation that networks will be needed post 2050. While this may be the case, it is also used to support arguments for higher returns because

there is a greater stranding risk arising from undepreciated assets. We have already submitted our views on accelerated gas network depreciation to Ofgem in our response to the RIIO-3 sector methodology consultation, and we would highlight the following:

- On **stranding risk**, we consider it is not appropriate or necessary to increase allowed returns on capital in compensation for an investor **perception** of increased risk to the long-term value of the RAV. This is a perceived rather than actual stranding risk for investors. The uncertainty for investors is about the methodology that will be used to address the issue.
- We aren't convinced that the gas network RAV needs to be fully depreciated by a certain date and believe that other solutions can be developed to address the potential stranding of residual RAV e.g. through taxation or socialising across consumer bills. On **intergenerational fairness**, we consider that accelerated depreciation based on ex-ante assumptions about asset usage long-term is unlikely to be a fair and appropriate way to address the risk of asset stranding. It is highly likely further intervention will be required to address the affordability of gas bills in the future, regardless of choices around depreciation. A solution is required that *fully* addresses this issue.
- Finally, given the expected future declining usage of the gas network, we suggest that Ofgem considers how future price controls may evolve e.g. if RAV is largely depreciated, then price controls rewarding investors through a return on RAV will not be effective and will need to be redesigned. Also, the difference between regulatory asset values and actual asset values will need to be addressed such that customers do not lose the value of assets they have fully paid for.
- **Investor returns – Cost of Equity (CoE):** Ofgem's sector methodology proposed a CoE range of between 4.57% and 6.35%, with a midpoint of 5.46%. The network companies have made alternative proposals in their Business Plans, asking for an increased CoE. However, we believe that Ofgem should not increase company returns as well as passing additional risks onto consumers. Our view is that the RIIO-3 regulatory regime

should significantly reduce risk for investors, and this should result in a CoE at the bottom of Ofgem's proposed range of 4.57% and 6.35%. This is supported by our analysis presented later in this report.

Innovation

Innovation funding under the RIIO framework is important for achieving Net Zero, improving efficiency, and benefiting consumers. However, transparency and clarity in Business Plans vary, with some companies failing to detail project deployment, funding allocation, and consumer impact. Despite being funded by consumers, a disproportionately small share of Network Innovation Allowance (NIA) funding is directed toward projects that directly benefit them, particularly vulnerable groups. To enhance accountability, companies must improve cost transparency, allocate funding more equitably, and present clear, consistent innovation strategies. Strengthening these areas will ensure innovation delivers tangible benefits and builds stakeholder confidence in the RIIO-3 period.

Vulnerability

We are encouraged to see evidence of collaboration within the GDNs' vulnerability strategies, and that vulnerability plans have been based on customer and stakeholder engagement (though companies offer differing levels of detail).

We would like to see the GDNs demonstrate how they plan to scale or wind down certain projects in the likelihood that their Vulnerability and Carbon Monoxide Allowance (VCMA) is significantly reduced in GD3.

Both Ofgem and the GDNs should ensure that all vulnerability work is centred around the framework that Ofgem itself set in RIIO-2 - that is, 'related to their existing areas of competence, activity, and consumer interaction'.¹ We do not feel that any plans to deliver energy efficiency measures should be included within the VCMA.

¹ Ofgem (2021) [RIIO-2 Final Determinations, GD Annex](#)

Independent Stakeholder Groups (ISGs)

All the Business Plans talked positively about the ISGs, highlighting their beneficial role in the creation of these Plans. However, there was inconsistency in the level of information provided by different companies in the ISG sections of their Business Plans. Some companies offered detailed insights into their ISGs' feedback and how they addressed it, while others provided only general information about the process they followed.

However, we have not been able to assess, and therefore raise a concern, the value that ISGs have added for consumers. For example, all companies have indicated that their business as usual costs will increase, however, based on our review of the ISG statements included in the Business Plans, we are not sure of the extent of challenge that the ISGs are able to provide on this.

Sector Specific Issues

Gas Transmission (NGT)

We support NGT's ambition to ensure green gas producers are able to connect to the NTS faster than current timelines. NGT proposes to consider upgrading natural gas assets to hydrogen-ready assets if the cost is similar. This may be a low regrets action should these assets be available. We also agree that there is a need for more focus on ensuring as close to real-time gas quality information is available.

Furthermore, we welcome the proposed introduction of the Collaborative Visual Data Twin (CVDT) project digital twin. We have seen innovation projects happen already on this so it is important that clear expectations on delivery in the early years of RII0-3 are set by Ofgem.

Incentives

Our main findings and observations are outlined below:

- NGT has provided very little detail on the rationale behind their incentive targets and proposed calibration in the main Business Plan.
- A target for procurement of NTS shrinkage is not included, making it difficult to assess whether the cap and collar of +/- £5 million is justified. It

is important for consumers that shrinkage is procured as efficiently as possible to minimise this cost for them.

- We are supportive of efforts to reduce NGT's operational emissions. We are aware that the new incentive proposed related to the deployment of recompression units is about deploying units which are already paid for through the price control. There is no evidence in the main Business Plan on how this incentive would alter NGT's behaviour from its current practice of deploying these units. It is therefore not overwhelmingly clear what the benefit of the new financial incentive would be for consumers or that this is the best way to achieve the intended outcome.
- There is no information in the main Business Plan on the justification for the greenhouse gas (GHG) fugitive emissions and associated target.
- Overall the information regarding incentives in the main Business Plan is insufficient, with the exception of the customer service incentive.
- We welcome the introduction of minimum response thresholds in the customer satisfaction incentive. We have been concerned that the incentive in RIIO-T2 is in some instances based on very low numbers of responses which may not be suitably representative on which to either reward or penalise NGT. It is important that more robustness is achieved in the incentive to ensure that rewards and penalties are justified in RIIO-T3.
- We note that incentive targets for customer service areas proposed (ranging from 8.2 to 8.6) sit both slightly below and only slightly above average existing performance in RIIO-T2 (8.49). In two of the 4 years of data reported by NGT, scores have been at or above 8.6. There is a risk that the proposed targets do not stretch the performance already achieved in RIIO-T2.
- We do not believe that setting targets based on an average of the last five years is a sufficiently ambitious methodology. It does not allow for recalibration around the service level now expected by customers. We believe setting targets at a percentile above 50% is a stronger methodology.

Electricity Transmission

As outlined in the finance section of our response, we are surprised to see all companies including the majority of their costs in uncertainty mechanisms

rather than baseline allowances. We believe there to be more certainty in RIIO-3 than in RIIO-2 due to the introduction of the transitional Central Strategic Network Plan (tCSNP) and more direction from the newly established NESO on exactly where new build is needed. We would like to see more justification from the TOs on why uncertainty mechanisms are favoured, and more oversight from Ofgem on how costs are allocated.

Community benefits plans are, in general, lacking some detail and consistency on funding mechanisms and delivery. While this may change when government guidance is issued in the Spring, the TOs should consider more collaborative working to ensure that community benefits do not become a postcode lottery.

Gas Distribution

Customer service

In the second year of GD2 (2020/21), all 8 licence areas exceeded their targets on planned interruptions, unplanned interruptions and connections. We therefore would like to see GDNs strive for stretching targets, and for Ofgem to calibrate the incentive going into GD3 to avoid over-rewarding companies.

Unplanned interruptions

The unplanned interruptions incentive can provide a useful tool in driving GDN performance, and ensuring that customers experience fewer instances of interruptions to their supply, and shorter waits for reconnection.

Ofgem asked the GDNs to propose a common output for non-Multiple Occupancy Buildings (MOBs) and a GDN specific target for average MOBs interruptions. We are pleased to see that all proposed targets are relatively aligned, and that the majority of companies agree that a penalty-only incentive would work best to improve and embed performance standards. We note examples of good practice in collaboration, such as SGN sharing mapping data with third parties, leading to a reduction in the total number of unplanned interruptions, and NGN's proposal to set up a workshop to share best practice with other GDNs. In light of this, we feel it may be best for Ofgem to set a baseline performance level (under which companies would incur a penalty) rather than introduce relative targets.

Disconnections

Ofgem has stated its intention for GD3 to include a new disconnections survey. We are supportive of data collection in this area, due to the potential for disconnections to increase as consumers decarbonise their home heating. Eventually, the survey results could roll into the ODI-F for customer satisfaction, ensuring that consumers receive a timely and efficient service.

There are disparities in the level of information provided on disconnections across the GDNs. SGN does not mention the disconnections survey or any plans around disconnection customer service, other than to forecast around 1,650 customer-funded disconnections per year. Cadent has a similar forecast, however WWU predicts that by 2032 it will be carrying out 4,000 disconnections each year.

Commitments to improving the customer experience for disconnections vary. Cadent intends to work collaboratively with the HSE and Ofgem to determine the policy framework, while NGN and WWU have made more specific plans, with NGN referring to 'enhanced voluntary service improvements' on disconnections once baseline results from the survey are available, and W&W will evolve its connections platform, including an app tracking engineer visits and troubleshooting AI, to deal with disconnections. While we accept that it is difficult for GDNs to precisely plan the extent of disconnections while the policy environment is changeable, it is important for the companies to anticipate future trends in order to best serve their customers.

Hydrogen

Ofgem will not provide funding for dedicated hydrogen-related activities during this period through the RIIO3 funding. As a result, network companies stated in their Business Plans that they will use alternative sources to finance their hydrogen projects.

Total Expenditure (Totex) assessment

This section reviews the Business Plans totex submissions for each sector and each company. It reviews their baseline submissions and any additional expenditure proposed for uncertainty mechanisms.

Gas Distribution

Utilisation of the gas distribution networks is expected to decline, primarily due to heat pump uptake in new and existing homes. However, companies must still deliver safe and reliable gas networks for their customers, including delivery of the iron mains replacement programme while customers are still connected to the gas network.

In their Business Plans, each company has sought to justify increased totex levels despite falling gas demand and network utilisation. Proposals to add uncertain costs through uncertainty mechanisms have also been included. This section considers the justifications provided by each company and across the sector.

Cadent

Totex: the Cadent totex bid for the 5 years of GD3 is shown below, seeking an increase of over £1 billion (16%) from the GD2 5-year allowance. Cadent have not provided any data tables with their plan so a breakdown of opex, repex and capex is not possible.

Table 2: Cadent Totex bid.

£m (2023/24 prices)	GD2	GD3	% change
Totex	6770	7820	16%

Cadent's justifications for this increase are summarised below, together with our comments:

New legislative/policy requirements (+£360 million) – this includes maintaining cyber and physical security, ensuring compliance with a new HSE workforce fatigue policy and effectively managing streetworks costs.

- We recognise that costs of complying with new mandatory requirements are necessary. We suggest that Ofgem carefully assesses proposed volumes and unit rates of such claims and consider the use of uncertainty mechanisms as appropriate.

Type of work (+£470 million) – this proposes higher costs for their iron mains replacement programme, resulting from more complex and higher cost assets having been left to the end of the replacement programme.

- We are concerned about why higher cost iron mains replacement expenditure has been left until the end of the programme. We presume this may mean Cadent has benefitted in prior price controls by completing lower cost replacement first. We therefore question whether it is right for consumers to face higher costs in GD3 if these higher costs were assumed to be part of the programme in RII0-2 and therefore part of the allowances. We request urgent clarity from Ofgem.

Advanced leakage management (+£290 million) – this proposes additional costs for leak detection and prevention, offering benefits from reduced emissions.

- While we support the reduction of leakage and associated emissions, we think the timing of further investment against a background of declining gas use will need to be carefully considered to ensure consumers do not pay for assets and activity which could deliver benefits which decline rather than increase.

Resilience (+£160 million) – this proposes to deliver several atypical projects to improve asset health and resilience.

- We oppose this and consider this should already be included in the business-as-usual asset management programme. Cadent appears to be asking for additional funding for higher cost projects that have been delayed from previous price controls.

Market factors (+£60 million) – these reflect higher insurance, property rental, vehicle and software licencing costs.

- We do not consider that these costs should be included – such costs can be managed by the companies and are already subject to inflation indexation. We consider they should already be included in business-as-usual totex, and subject to totex efficiency incentives.

Customer specific (+£80 million) – these costs are associated with new output commitments i.e. whole system planning (£25 million), data/digitalisation (£26 million), vulnerable customer funding (£24 million).

- We recognise that these activities may require new resource commitments for such activities which should deliver benefits to customers. However, these costs appear high, and we suggest Ofgem carefully assess whether the claimed volumes, unit costs and benefits are appropriate.

Ongoing efficiency (-£200 million) – Cadent proposes an ongoing efficiency of 0.5% per annum.

- We do not consider this to be particularly ambitious and suggest the ongoing efficiency target should be at least 1% per annum, consistent with the RIIO-2 levels.

Uncertainty Mechanisms: Cadent does not clearly define additional uncertainty mechanisms or associated costs in their plan.

Their plan mentions uncertainty mechanisms being needed for code manager implementation costs, employer national insurance contribution increases, streetworks costs, biomethane connections.

We note that other companies have already included such costs in their baseline totex forecasts and do not see that Cadent should be an exception. We suggest that Ofgem should apply a consistent approach – where costs can be managed by companies, efficient costs should be included in baseline allowances and be subject to totex incentives.

NGN

Totex: the NGN totex bid for the 5 years of GD3 is shown below, seeking an increase of £317 million (21%) from the GD2 5-year allowance.

Table 3: NGN Totex bid.

NGN	GD2	GD3	%
Opex	578	656	13%
Capex	311	331	6%
Repex	631	850	35%
Total	1520	1837	21%

NGN's justifications for this increase are summarised below, together with our comments:

Opex: NGN is forecasting a £78 million increase due to a new workforce fatigue HSE policy (+£42 million), increased maintenance workload (+£16 million), normal winter impact (+9 million), apprentice/training strategy (+£6 million) and other cost movements (+£31 million) which include automated leak detection and meter box replacement.

- We recognise that the costs of complying with new HSE policy on workforce fatigue is necessary. We suggest that Ofgem carefully assess proposed volumes and unit rates of this claim. The other opex claims appear to be activities that a well-performing company should undertake as a 'business-as-usual' activity and are not justified.

Capex: NGN is forecasting a capex increase of £20 million due to additional LTS storage and entry, offtakes and PRS, (+£52 million) which is offset by a reduction in connection costs (-£32 million) as GD2 annual customer connections of 3000 pa during GD2 are expected to fall to 1500 pa during GD3, driven by Government policy on the Future Homes Standard.

- We consider the £52- million of additional LTS expenditure should be excluded. It should already be addressed by the business-as-usual asset management programme. NGN appears to be asking for additional funding for projects that may have been delayed from previous price controls for company benefit.

Repex: NGN is forecasting a £219 million increase as more complex and higher cost iron mains replacement activities are required to complete the programme.

- We are concerned that NGN has sought to delay the higher cost iron mains replacement expenditure until the end of the programme, allowing it to benefit in prior price controls by completing lower cost replacement first. We do not agree that these additional costs should be allowed – customers have already paid for this replacement programme, and companies have benefited from phasing of costs. Customers should not have to pay a premium for this. We request urgent clarity from Ofgem.

Ongoing efficiency: NGN proposes an ongoing efficiency of 0.5% per annum.

- We note that NGN claims to be the leader in gas distribution efficiency, and they are currently underspending their GD2 allowance by some 11%. We do not consider the 0.5% annual target to be particularly ambitious and suggest the ongoing efficiency target should be at least 1% per annum, consistent with the RIIO-2 levels.

Uncertainty mechanisms: NGN states that they do not consider it appropriate to include anticipatory investment within baseline expenditure and therefore their baseline expenditure represents their 'best view' of GD3 expenditure with very minor exceptions. NGN's baseline includes forecasts for Tier 1 mains/services repx, NARM expenditure, and National Insurance additional costs.

NGN has proposed £12.5 million of Use it or Lose it (ULOLI) expenditure under the Net Zero and Power Reopener (NZARD) to support net zero projects including regional whole system planning and preparation for gas system decarbonisation.

Other than NZARD reopener costs, which appear reasonable, NGN appears to have a firm baseline bid which is welcome as it offers certainty to customers. However, the baseline totex bid shows a 21% increase from GD2 which may indicate that some contingency margin has been applied instead of seeking uncertainty mechanisms. We suggest Ofgem should review whether any elements of NGN's forecast totex should be subject to uncertainty mechanisms.

SGN

Totex: the SGN (including Southern and Scotland areas) totex bid for the 5 years of GD3 is shown below, seeking an increase of £766 million (21%) from the GD2 5-year allowance. SGN has not published Business Plan Data Tables with a breakdown of costs.

Table 4: SGN Totex bid.

£m (2023/24 prices)	GD2	GD3	% change
Opex	1445	1562	8%

Capex	760	905	19%
Repex	1485	1989	34%
Total	3690	4456	21%

SGN's justifications for this increase are summarised below, together with our comments:

GD2 workload and cost pressures (+£445 million) – SGN claims that cost forecasts for GD3 should be based on their costs in 2023/24 which are more reflective of future costs. A third of this increase is due to higher workload for repair, cyber and repex activities, and two-thirds is attributed to the implementation of HSE workforce fatigue policies and increasing cost of repex programme delivery.

- We don't agree this claim is justified, or that a single year's performance is a justification for a GD3 cost increase. Our GD2 analysis shows that SGN has underspent its allowance over the three years to 2023/24 and has also carried forward some enduring value adjustments. This would appear to demonstrate that the company has been able to manage these claimed cost pressures over this period.

External workload increases (+£199 million) – this is attributed to the implementation of HSE workforce fatigue policies, complying with Ofgem's digitalisation requirements, and increases in connection costs.

- While we agree that additional efficient mandatory costs for HSE policies should be included, we do not consider that additional allowances should be provided for digitalisation – this should be a business-as-usual activity, offering efficiency benefits to SGN as well. Given the number of connections are expected to fall during GD3, we don't think an increase in connection costs is justified – this cost should decrease instead.

Base scope increase (+£106 million) – this is attributed to an increase in the Tier 1 repex workload, and riser replacement activity. The plan also comments that some workloads will decrease in GD3.

External cost factors (+£338 million) – external contractor cost increases are anticipated for repex due to greater project complexity and supply chain constraints.

- We don't agree that additional allowance should be made for either repex volume or unit cost increases. We are concerned that SGN has sought to

delay the higher cost iron mains replacement expenditure until the end of the programme, allowing it to benefit in prior price controls by completing lower cost replacement first. We do not agree that these additional costs should be allowed – customers have already paid for this replacement programme, and companies have benefited from phasing of costs. Customers should not have to pay a premium for this. We request urgent clarity from Ofgem and the HSE on this.

Efficiency/innovation (-£232 million) – this reflects efficiencies of c£47 million pa that have been achieved in ED2 and will be continued in GD3.

- While past efficiency improvements are welcome and demonstrate the deliverability of ongoing efficiency challenges, we don't consider this is a relevant factor for the GD3 determination. These efficiencies are embedded and should provide a starting point for the GD3 efficiency analysis.

Ongoing efficiency (-£89 million) - SGN proposes an ongoing efficiency of 0.5% per annum.

- We do not consider the 0.5% annual target to be particularly ambitious and suggest the ongoing efficiency target should be at least 1% per annum, consistent with the RIIO-2 levels.

Uncertainty mechanisms: SGN have identified a range of uncertainty mechanisms in their plan. Some are already included in their baseline forecast and some are additional to this as described below:

- UIOLI (£87 million included in baseline), comprising Vulnerable and Carbon Monoxide Allowance – £43.6m, and Net Zero Reopener (NZARD) - £43 million.
- Volume drivers (£1472 million included in baseline), comprising Tier 1 mains/services (£1333 million), Reinforcement (£53 million), Tier 2a mains (tbc), Connections (£64 million), Disconnections (£22 million)
- Reopeners (£186 million not included in baseline), SGN propose to investigate the following projects further and propose they be included as reopeners.
 - Diversion/loss of claims (£22 million)
 - Resilience - Climate resilience (£11 million), Cyber resilience (tbc)
 - Data and digitalisation (tbc)

- HSE (complex distribution) (£31 million), cut offs/risers/policy change (tbc)
- SIU Biomethane (£15.8)
- South London Medium Pressure replacement project (£30 million)
- Net Zero Decarbonising Multiple Occupancy Buildings (£20 million)
- Net Zero Hydrogen blending (Edinburgh) (£6 million)
- Net Zero Digital Leakage Analytics (£50 million)

We are concerned about the number and scale of uncertainty mechanisms proposed by SGN. If they remain, they will shift a significant amount of SGN's cost risks to consumers. As things stand, customers face the risk of funding an excessive claim for baseline expenditure and on top of that face a further increase if these uncertainty mechanisms are triggered. We urge Ofgem to carefully examine the need and benefit for such uncertainty mechanisms and allowances.

WWU

Totex: the WWU totex bid for the 5 years of GD3 is shown below, seeking an increase of £492 million (29%) from the GD2 5-year allowance. WWU has not published full Business Plan Data Tables with a breakdown of costs, but some data is provided in their Business Plan Financial Model.

Table 5: WWU Totex bid.

£m (2023/24 prices)	GD2	GD3	% change
Opex	604	900	49%
Capex	467	429	-8%
Repex	627	861	37%
Total	1,698	2,190	29%

WWU considers that 96% of their additional expenditure is required to deliver core safety, legal, regulatory and statutory obligations. WWU's justifications for this increase are summarised below, together with our comments:

Operational opex (+£12 million) – this appears to reflect a forecast additional opex workload and associated costs.

- We note that WWU is currently underspending its GD2 allowance – its not evident from the Business Plan why these opex levels should increase.

Mains replacement (+£37 million) – these are additional costs associated with the HSE mandated Tier 1 mains/services replacement programme, driven by increased volumes and unit costs. Higher cost, more complex interventions are expected in GD3.

- As for other Gas Distribution Networks (GDNs), we don't agree that additional allowance should be made for either repex volume or unit cost increases. We are concerned that WWU may have sought to delay the higher cost iron mains replacement expenditure until the end of the programme, allowing it to benefit in prior price controls by completing lower cost replacement first. We do not agree that these additional costs should be allowed – customers have already paid for this replacement programme, and companies have benefited from phasing of costs. Customers should not have to pay a premium for this. We request urgent clarity from Ofgem.

Multiple Occupancy Building risers (+£5 million) – WWU state that these are largely driven by the volume of buildings that require replacement in GD3 over GD2.

LTS safety replacement (+£16 million) – WWU state that they are seeing a deterioration in their extensive LTS system in Wales and consider that replacement is now the only option.

Connections/reinforcement (-£16 million) – WWU anticipate a reduction in new connections and in associated mains reinforcement.

Resilience (+£26 million) – this additional investment in IT, cyber resilience and physical security is required to improve resilience.

Net Zero investment (+£5 million) – this is funding for WWU's net zero pathway.

Other (+£14 million) – it is unclear from the plan submission what is included in this category.

- While safety and resilience requirements must be addressed, expenditure may have already been provided. We suggest that Ofgem's analysis should consider whether the above cost claims are incremental mandatory activities or whether expenditure has been deferred from prior price controls.

Ongoing efficiency challenge (-£33 million) - WWU proposes an ongoing efficiency of 0.5% per annum.

- We do not consider the 0.5% annual target to be particularly ambitious and suggest the ongoing efficiency target should be at least 1% per annum, consistent with the RIIO-2 levels.

Uncertainty mechanisms: WWU considers that the GD3 period brings greater uncertainty and risk arising from the transition to net zero and the final years of the asset main replacement programme. WWU supports the Ofgem approach to uncertainty mechanisms and the continuation of existing mechanisms. WWU suggests that existing uncertainty mechanisms may be grouped e.g. legislative change, to aggregate materiality levels and simplify their application.

- It is unclear from the WWU plan whether they have costed potential uncertainties and whether they are already included in the baseline. We suggest that Ofgem should seek to ensure that data is consistently provided.

Gas Distribution Sector - Overall Comments

The aggregate totex bid for the 5 years of GD3 across all companies is £16.3 billion, a 19% or £2.6 billion increase on their GD2 forecasts of £13.7 billion. The following table summarises each company's proposed increase/decrease in the principal cost categories. Cadent did not publish a breakdown of their costs.

Table 6: Change from company GD2 forecasts to GD3 bids.

% change	Cadent	NGN	SGN	WWU
Opex	n/a	13%	8%	49%
Capex	n/a	6%	19%	-8%
Repex	n/a	35%	34%	37%
Total	16%	21%	21%	29%

It is important to note that these GD2 forecasts are taken from company forecasts based on the first three years of the price control, so may change. A common theme across NGN, SGN and WWU appears to be a 30%+ increase in their repex costs. WWU's opex increase appears significantly higher than others and it is difficult to explain. We suggest that Ofgem should investigate such differences further in their analysis.

From our above review of company-by-company totex, there appear to be a few common themes, namely:

- Iron mains replacement - all companies are concerned about higher repex costs as iron main replacement is becoming more complex and costly at the end of the programme. We are concerned that companies have simply deferred higher cost projects to the end of the programme to their benefit. We urge Ofgem to carefully consider whether companies have already been awarded allowances for this work and disallow expenditure where it is either inefficient or has already been funded.
- Ongoing efficiency – each company has proposed an ongoing efficiency of 0.5% per annum. We do not consider the 0.5% annual target to be particularly ambitious and suggest the ongoing efficiency target should be at least 1% per annum, consistent with the RIIO-2 levels.
- Additional asset replacement – some companies have identified additional work required that will be required, much for mandatory requirements. We suggest that Ofgem’s analysis should consider whether the above cost claims are incremental and are indeed mandatory activities or whether expenditure has simply been deferred from prior price controls.
- Net Zero – we note that expenditure provisions for Net Zero preparation e.g. regional whole system planning, have been proposed as specific UIOLI allowances. We would support this approach as a way of ensuring that expenditure is approved by Ofgem and is not duplicated by other net zero initiatives. Until Government policy for heat decarbonisation, particularly the relative role of hydrogen for heating, becomes clearer, customers should not be at risk of potential nugatory expenditure.

Turning to uncertainty mechanisms, it is difficult to ascertain from the Cadent and WWU plans what uncertainty mechanisms and associated costs have been included in the baseline totex bids. The NGN and SGN plans are clear in what has been included, but we have concerns about the SGN plan which appears to have a large element of totex which is subject to uncertainty mechanisms, thereby transferring risk to customers.

Finally, considering the GDN plans overall, it is concerning that the sector is seeking substantial increases in totex allowances. This is occurring in a sustained period of declining gas demand and near completion of the gas main replacement programme which should enhance safety and resilience.

We urge Ofgem to carefully scrutinise the company bids and ensure that value for money can be realised in this sector. **It does not seem credible that GDNs should receive above inflation totex increases at a time of declining gas demand and decreases in new customer connections.**

Gas Transmission

This section considers the proposals for totex and uncertainty mechanisms from the NGT GT3 plan. The plan aims to maintain safe and secure gas supplies while responding to reducing demand as gas power stations close.

Totex: the NGT totex bid for the 5 years of GT3 is shown below, seeking an overall increase of £720 million (22%) above the GT2 5-year allowance.

Table 7: NGT Totex bid.

£m (2023/24 prices)	GT2	GT3	% change
Load related capex expenditure	10	-	
Asset replacement capex expenditure	1,150	1,330	16%
Other capex expenditure	770	740	-4%
Non-operational capex	290	510	76%
Total capex	2,220	2,580	16%
Network operating costs (opex)	410	510	24%
Indirect costs (opex)	590	890	51%
Total opex	1,000	1,400	40%
Ongoing efficiencies		(60)	
Total	3,220	3,940	22%

NGT's justifications for this increase are summarised below, together with our comments:

The main Business Plan highlights additional expenditure requirements are for:

- Secure and resilient supplies (+£193 million capex) – this includes expenditure on asset health and resilience, cyber and physical security, and IT system health/new capability.
- Building and sustaining capability (+£573 million) – this includes expenditure on network health and resilience, investment plan growth, legislation/policy requirements, and improved skills/capabilities.

Very little information is provided in the main plan about why these cost increases are needed. The cost benchmarking annex contains more detail,

although much information is redacted. Further information may be available in Engineering Justification Papers, but these have not been reviewed in the time available. Highlights from the cost benchmarking annex are:

- Load related capex (£0 million) – no new connections are anticipated in GT2.
- Non-load related capex - this includes asset health, compressor modifications/network decarbonisation, and decommissioning costs. The plan notes that additional network flexibility investment may be needed to accommodate changes in gas flows. An additional £180 million of expenditure above GT2 is forecast.
- Other capex – relating to physical and cyber security which is provided in confidence to Ofgem.
- Non-operational capex – this includes IT/telecoms, vehicles, property, small tools/equipment, and net zero development costs. An increase of £218 million is forecast over GT2 levels.
- Direct network operating costs – this includes repair and maintenance and system operation costs. An increase of £100 million is forecast over GT2 levels. System operation activities include preparing for hydrogen blending on the gas network.
- Indirect costs – this includes support activities such as asset management, operational IT, training and engineering support. Business support activities include management, HR, finance, IT and legal services. An increase of £300 million is forecast over GT2 levels.

Efficiency improvements (-£58 million) – Ongoing efficiencies are stated as £58 million or 1.5% of totex over the GT2 period. *We estimate this is around 0.5% p.a. and we do not consider this target to be particularly ambitious and suggest the ongoing efficiency target should be at least 1% per annum, consistent with RIIO-2 levels.*

As shown above, all capex and opex cost areas show significant increases despite the declining gas demand for power generation. This decline is expected to accelerate over the RIIO-3 price control period following the Government's publication of its Clean Power 2030 plan in December 2024. We also note that NGT is currently underspending its GT2 allowance by 17% albeit this is categorised as an enduring value adjustment and expenditure may be incurred later.

As for gas distribution, we urge Ofgem to carefully scrutinise the NGT bid and ensure that value for money can be realised, especially to minimise the risk of nugatory expenditure e.g. in hydrogen blending. **It does not seem credible that NGT should receive above inflation totex increases when Government policy seeks to accelerate gas demand decline.**

Uncertainty mechanisms: the NGT plan identifies £1.31 billion of additional uncertainty mechanisms as illustrated below.

Table 8: NGT Uncertainty mechanisms.

Uncertainty mechanisms	£m
Asset health/security of supply	770
Compressor emissions/climate change adaption	380
System efficiency – IT/telecoms and property	170
Total	1,310

If all of these uncertainty mechanisms are added to the NGT totex baseline bid, then it results in a total bid of £5,250 billion, an increase of £2,030 million or 63% from GT2 levels against a background of declining gas demand. The specific triggers for this expenditure, and the amount needed are unclear from the information provided.

We would question whether any of this uncertainty expenditure claim has been justified – it just seems to provide a totex contingency for the company. We urge Ofgem to investigate whether any of this uncertainty is necessary and ensure that customers are not exposed to unnecessary risk.

Electricity Transmission

Totex and Uncertainty Mechanisms

Over recent years electricity transmission investment has significantly increased to deliver against net zero targets. This is expected to continue during the ET3 period, driven by the acceleration of offshore wind farm connections and associated reinforcements.

In their Business Plans, each company has sought to justify increased totex levels. Proposals to add uncertain costs through uncertainty mechanisms have also been included. This section considers the justifications provided by each company and across the sector.

SHET

Totex: the SHET totex bid for the 5 years of ET3 is shown below. Combining their baseline and committed uncertainty mechanism bids results in a funding request of £22.3 billion, which more than trebles their ET2 5-year allowance, which we currently understand is £7.1 billion (in 2023/24 prices).

Table 9: SHET ET2 totex bid (£2023/24 prices).

1. ET2 Baseline	£m	2. Committed Uncertainty mechanisms	
Load related projects	1,421	Load related capex (ASTI)	13,425
Non load related capex	1,369	Load related capex (LOTI)	1,952
Legacy ET1/ET2 costs	153	Network Operating Costs	27
Non operational capex	824	Indirect operating costs	791
Network operating costs	389	Total committed UMs	16,195
Support costs	1,626		
Market capacity adj.	177	Total (1 +2)	22,319
Other costs	165		
1. ET2 Baseline	6,124		

Of their baseline expenditure, SHET highlights that £4.7 billion is needed largely to maintain high standards of network reliability and resilience (46 projects), enable digital and cyber ambitions, and support their growing business. We understand this to be all their costs except load-related capex. If this is the case, then their forecast of £4.7 billion represents a near trebling of costs from the £1.7 billion of equivalent costs we understand are currently forecast for ET2.

The SHET plan and supporting annexes provide little further information. Business Plan Data Tables have not been published. We find it very difficult to assess whether the SHET load and non-load cost increases described above are needed and represent value for money for consumers. We must rely on Ofgem undertaking this analysis.

But we are concerned that such vast increases cannot be effectively forecast or assessed by Ofgem, leaving a risk of windfall gains by companies if allowances are too high. We suggest that Ofgem seeks to introduce measures e.g. reducing the power of totex incentives, to mitigate this risk.

Uncertainty Mechanisms: SHET have also identified further expenditure that may be needed under an uncertainty mechanism framework. This is detailed in the table below.

Table 10: SHET Future Uncertainty mechanisms.

3. Future uncertainty mechanisms (£m 2023/24 prices)	
ET3 connections	1,511
Beyond 2030 connections	7,443
Indirect operating costs	459
Total future UMs	9,413
Grand Total (1 + 2 + 3)	31,732

It is difficult to identify the breakdown of these additional uncertainty mechanisms from the plan document. Given the potential scale of these, we suggest that Ofgem's assessment clarifies the potential need and individual costs of the projects included in this assessment so the impact on totex and customer bills can be consistently assessed.

If these additional load related investments (and associated support costs are needed), then the ET2 totex allowance for SHET will more than quadruple from current levels. Annual load related capex could potentially increase tenfold from current SHET ET2 levels of around £1 billion per annum. This raises issues of whether SHET can successfully deliver at this scale and whether customers will face additional costs and risks if they cannot.

We suggest that Ofgem considers these risks and the availability of potential alternative transmission providers via competition, before agreeing to allocate some or all these future projects to SHET. Competition for future assets should secure efficient cost and delivery commitments to benefit customers.

SPT

Totex: the SPT totex bid for the 5 years of ET3 is shown below. Their baseline bid is for £10.5 billion, around treble their ET2 5-year allowance of £3.4 billion.

Table 11: SPT ET2 totex bid (£2023/24 prices).

£m (2023/24 prices)	ET2	ET3	% change
Load related capex	1,980	7,934	301%

Non-load related capex	545	523	-4%
Non operational capex	18	117	550%
Network operating costs	180	353	96%
Indirects (opex)	425	1,039	144%
Business support	187	481	157%
Other costs	98	105	7%
Total	3,433	10,552	207%
Uncertainty mechanism		7,863	
Grand total		18,415	436%

Of their baseline expenditure, we note that all SPT non load expenditure totals £1.6 billion in ET2 and increases by 80% to £2.8 billion in ET2. This is a significantly lower percentage increase than that forecast by SSEN for a similar growth profile. We suggest that Ofgem should examine this difference further to ensure that only efficient costs are allowed.

As for SHET, we are concerned that such vast totex increases cannot be effectively forecast or assessed by Ofgem, leaving a risk of windfall gains by companies if allowances are too high. We suggest that Ofgem seeks to introduce measures e.g. reducing the power of totex incentives, to mitigate this risk.

Uncertainty Mechanisms: SPT have identified 16 further load related reinforcement projects where there is uncertainty about scope, timing and cost. These will be developed during the RIIO-3 period and assessed through the load-related reopener process as required. These projects appear to represent only around £1.6 billion of the above uncertainty mechanism total which is presented in the SPT Business Plan Data Tables.

It is difficult to identify the breakdown of these additional uncertainty mechanisms from the plan document. Given the potential scale of these, we suggest that Ofgem's assessment clarifies the potential need and individual costs of the projects included in this assessment so the impact on totex and customer bills can be consistently assessed.

National Grid Transmission

Totex: the NGET totex bid for the 5 years of ET3 is shown below. Their baseline bid shows an 8% increase for ET3 but increases to 167% once both committed

and future potential uncertainty mechanisms are included. ET3 expenditure could potentially increase to £35 billion. NGET forecast that annual totex could rise to c£8 billion per year by around 2030, a fourfold increase from current levels.

Table 12: NGET ET3 totex bid.

£m (2023/24 prices)	ET2	ET3	% change
Load related capex	3,000	4,100	35%
Non-load related capex	2,200	1,500	-32%
Non operational capex	500	700	62%
Network operating costs	1,600	2,000	26%
Indirects (opex)	2,200	2,100	-7%
Business support	600	600	2%
Other costs	400	300	-26%
Total	10,400	11,200	8%
Uncertainty mechanisms (pipeline log)	2,600	23,700	
Total with uncertainty mechanisms	13,000	34,900	8%
Innovation	100	200	
Grand total	13,100	35,100	167%

From these high-level numbers, we note that NGET underlying (non-load) baseline expenditure appears to remain relatively constant compared to SPT and SSEN forecast increases. But we note that the ET3 uncertainty forecast includes £2.6 billion of expenditure attributable to ‘secure and resilient supplies.’ NGET has not published Business Plan data tables, so it is difficult to assess further. We suggest Ofgem examines the different forecasts to determine a consistent approach to presentation and assessment of these forecasts.

As for the other Transmission Operators (TOs), we find it difficult to assess whether the NGET load and non-load cost increases described above are needed and represent value for money for consumers. We rely on Ofgem undertaking effective analysis.

Given the scale of change, we are concerned that such vast increases cannot be effectively forecast by companies or assessed by Ofgem, leaving risks of windfall gains by companies if allowances are too high. We suggest that Ofgem seeks to

introduce measures e.g. reducing the power of totex incentives, to mitigate this risk.

Uncertainty Mechanisms: NGET's uncertainty mechanism forecast is discussed above. We note that, in addition to load-related reopeners, NGET is also proposing uncertainty mechanisms for non-load works, opex escalators in association with investment, Central Strategic Plan costs, physical security and innovation projects.

While UMs do reduce risk for customers from windfall gains for companies from excessive ex-ante allowances, they also reduce risks for companies by passing manageable cost risks to consumers. The introduction of non-load reopeners may fall into this latter category. We suggest that Ofgem carefully assesses the benefits of such uncertainty mechanisms before agreeing their introduction.

Electricity Transmission Sector - Overall Comments

The aggregate totex bid for the 5 years of ET3 for all companies is shown below:

Table 13: Change from company ET2 forecasts to ED3 bids.

	ET2	ET3		
£m (23/24 prices)	Forecast	Baseline	Future UMs	Total
SHET	7,100	16,195	9,413	31,732
SPT	3,433	10,552	7,863	18,415
NGET	13,100	11,200	23,700	35,100
Total	23,633	37,947	40,976	85,247

The baseline increase shown above totals some £38 billion, a 76% increase over ET2. If uncertainty mechanisms for additional expenditure were to be triggered, then this could potentially increase to some £85 billion, almost a four-fold increase from ET2. Also, we note that these plans have been developed in advance of the Government's Clean Power 2030 plan and the forthcoming NESO spatial plan, which may cause further increases.

From our above review of company-by-company totex, we would raise the following areas of concern, namely:

- Understanding ET2 totex performance – we have used company ET2 forecasts to consider their ET3 bids but are concerned that these are not consistent or reliable. Our analysis of ET2 totex to date indicates that NGET and SPT are currently underspending by c20% but this falls to near zero after enduring value adjustments. By contrast, SSEN has an underspend of c16% and makes little use of enduring value adjustments. But all ET companies appear to include historic commitments in their ET3 forecasts. We suggest Ofgem ensures consistency and transparency of ET2 totex information to provide confidence about the starting point and foundation for the ET3 totex regime.
- ET3 load related expenditure – vast increases are proposed but supporting evidence to assess and compare value for money is limited - neither NGET nor SHET has published Business Plan data tables, and SPT information is limited. For example, it is unclear whether projects approved under the ET2 and ASTI programmes have experienced cost increases, and whether the need and costs for new projects are justified.
- Efficiency of ET3 non-load expenditure – we note that the SSEN and SPT plans appear to seek significant commensurate increases in non-load capex and opex expenditure alongside load related capex. NGET does not appear to have sought such an increase. Ofgem should carefully scrutinise whether claims for increases in residual costs are justified. We consider that ongoing efficiency targets should still be applied to residual costs.
- Uncertainty mechanisms and price control deliverables – well-designed uncertainty mechanisms should mitigate risks of excessive ex-ante allowances, and project-based price control deliverables can add project specific incentives to ensure cost efficient and timely delivery. This should benefit consumers. Many such projects are likely to be included in ET3, each essentially having their own price control. We are concerned about whether each project can be monitored and incentivised effectively by Ofgem over an extended period. Such projects may become a cost pass through as companies justify ongoing internal and external cost increases.
- Delivery risk – we are concerned that the scaling up of transmission totex increases the risk of inefficiency and delayed delivery, with such costs to be borne by customers. We suggest Ofgem assesses whether each of the companies has demonstrated the capability to deliver an accelerated capex programme of such scale within the time specified. Competition for asset delivery should be considered as an alternative.

Finally, considering the ET plans overall, the sector faces a huge challenge in delivering substantial increases in totex allowances, with uncertainty about volumes, delivery costs, and benefits. As described above, this will place considerable stress on the current ex-ante incentive-based regulatory model. As such, we suggest this requires a radical rethink of how Ofgem monitors and regulates ongoing expenditure and progress against plan. We suggest that accountability is enhanced through regular public reporting by Ofgem on delivery performance and the application of incentives.

We urge Ofgem to carefully scrutinise the electricity transmission bids and ensure that value for money can be realised in this sector.

Business Plan incentive

Ofgem's business planning guidance states that companies should provide concise business plans and gives a list of annex headings for further documents and tables to be provided.

For RIIO-3, Ofgem is again using a Business Plan Incentive (BPI), which consists of three stages:

- Stage A which requires the Business Plan to provide the minimum amount of information to set the price control effectively. There will be a penalty of 20 bps of RoRE if this requirement is not met.
- Stage B assesses whether the costs are adequately justified and efficient. There will be a reward of 40bps and a penalty of 20bps
- Stage C assesses the quality of the Business Plan in the round. There will be a reward or penalty of 20bps.

Ofgem guidance states they will be making their decision on the BPI with regard to the principles of transparency, accountability, proportionality and other principles of regulatory best practice. Ofgem will also assess the fulfilment of the minimum requirements only on the information provided in the first submission of the Business Plan.

In the limited time available since plan publication, we have reviewed the information published by each company and have set our initial views on each of these BPI stages below.

Stage A – transparency: We have reviewed the information published by each company as part of our response and have observed significant differences in the granularity of information that each has published. For example, most companies have not published their Business Plan data tables of financial models which allow more detailed independent analysis and comparison of their Business Plan forecasts. Furthermore, most companies have not published details of their asset health (NARM) forecasts which should justify non-load expenditure claims.

The following table sets out our summary of some key supporting documents (as defined by Ofgem's annex list) which we would expect to be published by

each company to justify their Business Plan. We note that some companies have redacted information for publication but are concerned that this has been redacted to avoid independent scrutiny rather than for confidentiality reasons. It is not clear whether the failure to publish information is because the supporting information is not available, or whether it has only been provided to Ofgem.

The key documents listed below include the Business Plan data tables (BPDTs) which should contain information to support expenditure and revenue claims and allow comparisons between plans.

Table 14: Business Plan transparency.

Business Plan Transparency	Cadent	NGN	SGN	WWU	NGT	NGET	SPT	SHET
Cost Assessment and Benchmarking								
Investment Decision Packs (IDPs)			On request					
Business Plan Data Templates (BPDT)				2 pages			1 page	
Business Plan Financial Model (BPFM)								
Network Asset Risk Metric (NARM) BPDT								

Published
 Not Published

Based on the public information we have reviewed; NGN has published the most evidence to support their plan e.g. full Business Plan data tables; next are WWU, NGT and SPT e.g. they have also published full or partial data tables; SHET, NGET and Cadent have provided the least evidence. In our view, only NGN has clearly provided sufficient information to merit a stage A incentive under the BPI.

Stages B and C: For stage B, we have outlined our concerns on cost efficiency for each company elsewhere in this response. For stage C, we would reiterate our comments for stage A.

Customer bill impact

Each of the company plans included information on the impact their plans will make on customer bills. Customer bills will be impacted by a range of factors including totex increases, rates of return and changes to depreciation policy. The headline impacts stated in each plan are:

- NGET forecast that the transmission element of customer bills will increase from £23 in 2026 to £44 in 2031, an increase of £21
- SHET forecast that the transmission element will increase from £45-50 today to £110-£130 per consumer per year by the early to mid 2030's
- SPT forecast that their costs will add an average £6.47 to customer bills over the ET3 period.
- NGT forecast that their gas transmission plan will add £1.34 to customer bills
- Cadent forecast that gas distribution costs will increase from £157 to £214, an increase of £57.
- NGN forecast an increase from £170 to £209, an increase of £39.
- SGN forecast an increase from £150 to £240, an increase of £90.
- WWU forecast an increase from £153 to £244, an increase of £91.

There are significant differences between these forecasts, apparently because different calculation approaches and assumptions have been used. For example, these forecasts may include different assumptions about totex levels (e.g. they may or may not include uncertainty mechanism totex), allowed rates of return and inflation. The GDN forecasts are increased due to accelerated depreciation policies required by Ofgem. As such it is difficult to compare or combine these forecast impacts.

Given the potential magnitude of this customer bill change, we think it is important that Ofgem should calculate increases using common assumptions and then publish the individual and combined impact of these company bids. This should be completed without delay to effectively inform public debate on the impact of these plans.

Financial considerations

This section reviews the Business Plan submissions on financial issues. We focus primarily on two issues, namely:

- Regulatory depreciation – decisions around accelerated depreciation of gas networks is a key issue for consumers and for gas companies
- Cost of Equity (CoE) - company bids for higher investor returns, if allowed, will increase costs to consumers

These are discussed further below.

Regulatory depreciation in gas networks

Future usage of gas transmission and distribution networks is expected to decline rapidly, commensurate with the transition from fossil fuels needed to achieve Net Zero targets by 2050. Currently, these assets are depreciated over 45 years, and the networks face a risk of asset stranding. To mitigate this risk. Ofgem's RIIO-3 sector methodology included a decision to apply accelerated regulatory depreciation for gas network RAV (Regulatory Asset Value), noting further work was needed to determine the most appropriate approach.

The gas network companies have made the following comments on this subject in their Business Plans:

- NGT consider that most of their existing network will either be repurposed or retained post 2050, and that action to accelerate depreciation is not necessary. Early depreciation may simply result in current gas customers being charged more than necessary.
- Cadent believes its network will be required beyond 2050 and that Ofgem should only accelerate depreciation on new assets. This results in the lowest customer bill impact and retains a RAV balance beyond 2050 in line with their expected network usage. Accelerating RAV recovery may give negative signals to investors.
- SGN note that one of the objectives of accelerated depreciation is to reduce the risk to investors of stranded assets and avoid undermining investor confidence. SGN are concerned that this will result in a lower RAV and will undermine the investment case by providing insufficient

compensation for risk. SGN propose that the rate of accelerated depreciation is aligned with the reduction in customer connections.

- NGN raise concerns about intergenerational fairness, where present consumers may pay a disproportionate amount if network usage continues for longer. Unless the gas network RAV is underwritten by Government, some stranding risk will remain, and this should be recognised through higher investor returns.
- WWU are concerned that Ofgem's proposed return on equity is too low in the context of the accelerated depreciation assumptions.

The gas network companies generally seek to argue for longer depreciation periods based on an expectation that networks will be needed post 2050. While this may be the case, it also supports their arguments for higher returns because there is a greater stranding risk arising from undepreciated assets. Some companies propose alternative approaches for shaping the depreciation profile to better address intergenerational fairness.

We have already submitted our views on accelerated gas network depreciation to Ofgem in our response to the RIIO-3 sector methodology consultation, and we would highlight the following:

On stranding risk, we consider that it is not appropriate or necessary to increase allowed returns on capital in compensation for an investor **perception** of increased risk to the long-term value of the RAV. This is a perceived rather than actual stranding risk for investors. The uncertainty for investors is about the methodology that will be used to address the issue. To address this perception, we suggest that Ofgem explore with Government what assurances can be provided to negate claims about asset stranding risk.

We aren't convinced that the gas network RAV needs to be fully depreciated by a certain date and believe that other solutions can be developed to address the potential stranding of residual RAV e.g. through taxation or socialising across consumer bills. On intergenerational fairness, we consider that accelerated depreciation based on ex-ante assumptions about asset usage long-term is unlikely to be a fair and appropriate way to address the risk of asset stranding. It is highly likely further intervention will be required to address the affordability of gas bills in the future, regardless of choices around depreciation. A solution is required that *fully* addresses this issue.

Finally, given the expected future declining usage of the gas network, we suggest that Ofgem considers how future price controls may evolve e.g. if RAV is largely depreciated, then price controls rewarding investors through a return on RAV will not be effective and will need to be redesigned. Also, the difference between regulatory asset values and actual asset values will need to be addressed such that customers do not lose the value of assets they have fully paid for.

Investor returns – Cost of Equity

Ofgem's sector methodology proposed a CoE range of between 4.57% and 6.35%, with a midpoint of 5.46%. The network companies have made the following alternative proposals in their Business Plans, supported by many expert studies commissioned to support their arguments.

- **NGET** proposes a cost of equity of 6.31% PFIH real at 60% gearing (5.83% at 55% gearing). The main reasons are:
 - The cost of equity must be sufficient to attract new equity under current market conditions.
 - The forward risk profile is increasing with the scale of new investment, new technology, supply chain, and labour constraints. There are downside impacts from the new ASTI framework.
 - Market cross checks e.g. September 2024 analysis of yields on long dated UK government and investment grade corporate bonds.
- **SPT** proposes a cost of equity of 6.86% at 60% gearing (6.57% at 55% gearing). The main reasons are:
 - Risks have increased since ET2, including size/scale of investment, supply chain/procurement costs and delivery incentives.
 - Their cross-checks calculate that the RFR, TMR and beta are all above Ofgem's CoE midpoint.
- **SHET** proposes a cost of equity of at least 6.5% at 60% gearing to persuade investors that the sector is investable. The main reasons are:
 - Electricity transmission is facing a global competition for capital.
 - The risk profile in ET3 is higher compared to ET2 and other utilities.

- Their cross-checks calculate that the RFR, TMR and beta are all above Ofgem's CoE mid point. They argue that Ofgem's reliance on Market to Asset Ratio's (MARs) is unjustified.
- **NGT** proposes a cost of equity of 6.48% at 60% gearing.
 - The gas sector is facing higher risks due to future uncertainty.
 - Interest rates and macroeconomic risks have increased since GT-2.
 - Market cross-checks show a cost of equity above Ofgem's range.
- **Cadent** proposes a cost of equity that should be no lower than 6.3% (assuming 60% gearing). The main reasons are:
 - There has been a shift in the last 2-3 years from historically low interest rates to a higher for longer interest rate environment.
 - The increasing awareness of investors about the potential risks of investing in a gas distribution network given future uncertainty.
 - Their cross-checks calculate that the RFR, TMR and beta are all above Ofgem's CoE mid-point.
- **SGN** proposes a cost of equity of 6.7% is needed to offer attractive returns to investors. The main reasons are:
 - the capital market and macroeconomic context is markedly different from when the GD2 control was determined.
 - Ofgem's sector methodology for determining cost of equity is incorrect. The range should be 7-7.4%, with a midpoint of 6.7%.
- **NGN** proposes a cost of equity of 6.36%, the top of Ofgem's range. The main reasons are
 - The gas sector faces higher risks due to the uncertainty of the longer-term role of gas in the UK energy mix.
 - Ofgem's CoE calculation does not take account of latest market evidence, and should be higher to attract investment.
- **WWU** proposes a cost of equity of 6.89%. The main reasons are:
 - risks associated with the future of the gas network, including the depreciation of the gas network.

- Ofgem's sector methodology does not accurately calculate the cost of equity and cross checks show the level should be higher.

The company proposals are listed below ranging from 6.3% to 6.9%:

Table 15: Company CoE proposals.

Cost of Equity (60% Gearing)	%
NGET	6.31%
SHET	6.50%
SPT	6.86%
NGT	6.48%
Cadent	6.30%
NGN	6.40%
SGN	6.70%
WWU	6.89%
Submission range – 6.30 to 6.89	
Ofgem SSMD	5.46%

Company arguments for an increased CoE are generally consistent, including:

- Risks have increased for electricity companies from major new asset investment programmes (and Ofgem's delivery incentive).
- Risks have increased for gas transmission and distribution companies due to the uncertain future of gas.
- Ofgem's methodology to calculate equity returns is incorrect and too low; macroeconomic factors are not reflected properly.
- Ofgem's market cross checks are incorrect and should be discounted.

We urge Ofgem to learn from experience and not repeat the same errors as in RIIO-2. We make the following points for Ofgem's consideration:

Information asymmetry

In our response to Ofgem's RIIO-3 Sector Specific Methodology Consultation² we set out our concerns that the RIIO-3 cost of capital will likely be set too high. We don't believe that the UKRN-based methodology being applied by Ofgem will ensure value for money and general affordability of consumer bills. This is due

²https://assets.ctfassets.net/mfz4nbgura3g/3OnSfRmzoYoRSkEe15909G/230e8f381b1c7969f9dbf08c31d07416/RIIO-3_SSMC_response__2_.pdf

to UKRN's guidance bringing together existing methodologies and so consolidating the positions of regulated companies that have a commercial incentive to deliver high returns.

Ofgem's approach for RIIO-3 therefore accepts the established positions of the regulated companies. It doesn't acknowledge or reflect that there are also alternative positions from consumer bodies - i.e. Citizens Advice - that deserve meaningful scrutiny and attention. There is a clear information and commercial asymmetry between companies and consumer bodies. This is illustrated already by many companies declining to publish important supporting information to their December 2024 RIIO-3 plans. Without attempts to remove the asymmetries between companies and consumer advocates, the trend of inflated network profits will likely continue into RIIO-3.

We are concerned that Ofgem's cautious approach to determining CoE e.g. aiming up, will result in overly generous returns. As explained above, there are systematic reasons why the Ofgem CAPM approach is likely to overestimate CoE. We recommend that cross-checks should be put to greater use.

Increased risks

Each company plan claims that their equity risks increase for RIIO-3, whether it be gas companies concerned about asset stranding or electricity transmission companies concerned about major capex project delivery risk. We do not believe these claims are substantiated:

- Electricity transmission: the RIIO-3 price controls include proposals for large amounts of new capex required to deliver Clean Power 2030 and Net Zero 2050 decarbonisation targets. Companies have requested significant amounts of expenditure to be included as uncertainty mechanisms, with scope, cost and timing of expenditure yet to be agreed.

We consider that the current regulatory arrangements under RIIO-2 and the ASTI programme, already serve to reduce investment risk for the companies, and these arrangements are likely to continue in RIIO-3. The current Price Control Deliverable (PCD) arrangements used by Ofgem for both baseline and uncertain projects effectively act as a cost pass through for the companies.

Current PCD regimes for major projects include incentives for timely delivery to a target cost, with a reward/penalty scheme. This is intended to

operate in a similar way to major construction contracts, but there is provision for adjusting scope, timing and costs due to factors outside the company's control. Also, to avoid delays in the ASTI regime, Ofgem has accepted budget costs as efficient without further scrutiny. We consider that the PCD regimes for major projects are lower risk than normal price control totex incentives – companies can claim for allowance changes as project parameters change, and in any case, can pass any late delivery or cost overrun penalties onto their contractors for these projects.

- Gas networks – as described above in our comments on regulatory depreciation, we do not believe that the gas networks face any increased risk from stranded assets. Ofgem's proposed accelerated depreciation approach should address this risk.

Overall, we do not find the company arguments that they and their investors are facing higher risks for RIIO-3 to be convincing. Our view is the opposite. Ofgem should not increase company returns as well as passing additional risks onto consumers.

Cross checks

In determining CoE, we consider it important that Ofgem consider appropriate cross checks to assess actual measures of an investor's perception of risk.

In June 2022, Ofgem published a MAR inference model within its electricity distribution price control draft determination (ED2)³. Ofgem used this MAR model to infer a CoE from recent transactions involving monopoly network companies. Ofgem found that the transactions are consistent with a CoE range of 3.2% to 3.9%⁴.

Analysis below has applied Ofgem's MAR inference model to the recent transaction of ENWL⁵ in August 2024 in a table alongside the calculations Ofgem presented in its ED2 draft determinations.

³ "RIIO-ED2 Draft Determinations – Finance Annex", Ofgem, June 2022. Page 181

⁴ "RIIO-ED2 Draft Determinations – Finance Annex", Ofgem, June 2022. Page 44

⁵ Iberdrola, Acquisition of Electricity North West, August 2024

Table 16: Ofgem's Market to Asset Ratio inference model and ENWL transaction

Component	WPD	Bristol	SGN	NGGT	ENWL	ENWL	ENWL	Formula
Baseline allowed ROE	4.65%	4.09%	4.55%	4.55%	5.43% ⁶	5.43%	5.43%	A
Expected Outperformance	2.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	B
Real ROE	6.65%	5.09%	5.55%	5.55%	6.43%	6.43%	6.43%	C = A + B
CPIH	2.00%	2.00%	2.00%	2.00%	2.00% ⁷	2.00%	2.00%	D
Nominal ROE	8.65%	7.09%	7.55%	7.55%	8.43%	8.43%	8.43%	E = C+D
RAV Growth (Real)	2.00%	2.00%	2.00%	0.00%	0.00%	1.00%	2.00%	F
RAV Growth (Nominal)	4.00%	4.00%	4.00%	2.00%	2.00%	3.00%	4.00%	G = D + F
Dividend pay-out ratio	70%	61%	64%	100%	100%	84.45%	68.90%	H = 1 - F/C
Dividends paid	4.65%	3.09%	3.55%	5.55%	6.43%	5.43%	4.43%	I = H * C
Market to Asset Ratio (MAR)	1.61	1.44	1.35	1.3	1.44 ⁸	1.44	1.44	J
Notional Gearing	60%	60%	60%	60%	60% ⁹	60%	60%	K
Equity Multiple	2.53	2.10	1.88	1.75	2.10	2.10	2.10	L = (J-K)/(1-K)
Real Cost of Equity	3.80%	3.50%	3.90%	3.20%	3.06%	3.59%	4.11%	M = I/L + C-I

The ENWL transaction based on Ofgem's model suggests a potential real cost of equity between 3.06% and 4.11% depending on real RAV growth suggesting that returns in this sector are already too high and the difference between baseline allowed return on equity and real cost of equity has grown since Ofgem produced this analysis for ED2.

⁶ Ofgem, [RIIO-3 SSMD Allowed Return on Equity Early View Summary Calculations](#)

⁷ Ofgem, [RIIO-3 SSMD Finance Annex](#)

⁸ Iberdrola, [Acquisition of Electricity North West](#), August 2024

⁹ Ofgem, [RIIO-3 SSMD Allowed Return on Equity Early View Summary Calculations](#)

Iberdrola have also said they paid a 44% premium for ENWL¹⁰ demonstrating that these companies are already highly attractive investments.

In May 2024, NG announced a £7 billion rights issue to help fund its proposed investment strategy between 2025 to 2029. The issue was the largest registered in the UK since 2009. The terms were typical for such issues and the acceptance rate was over 90%. This demonstrates that, despite the uncertainty about investment scale, timing and returns, and the RIIO-3 regulatory regime, investors found the issue highly attractive. This demonstrates that Ofgem's CoE methodology is already highly attractive to investors.

In May 2024 National Grid (NG) who own both Transmission and Distribution network companies in GB announced a £7billion Rights Issue (RI)¹¹. They offered a 34.7% discount to the theoretical ex-rights price¹², within the average interval for UK companies¹³. The offer had a 91% acceptance rate¹⁴, within the average range for the UK¹⁵. The RI was the largest one registered in the UK since 2009¹⁶ and the issue was a part of NG's proposed investment strategy for the financial years of 2025 - 2029¹⁷.

This was a remarkably successful RI with investors purchasing additional shares despite not being associated with clear investments, timings or returns as well as taking place ahead of Ofgem's RIIO-3 methodology decision in July 2024.

This strongly indicates that Ofgem's existing cost of equity methodology is already providing exceptional attractiveness to investors and that rather than being higher, cost of equity returns could be lower than RIIO-2 without impacting the ability for NG to attract and retain capital.

Raising £7billion of equity in one day without warning suggests capital is available, plentiful and financeable.

¹⁰ Iberdrola, [Acquisition of Electricity North West](#), August 2024

¹¹ ["Results of Rights Issue"](#) London Stock Exchange, 7 April 2024.

¹² ["NG Announces Fully Underwritten £7bn Rights Issue"](#), NG, 7 April 2024.

¹³ ["Encouraging Equity Investment"](#), Association of British Insurers, July 2013, page 36.

¹⁴ ["Top News: NG Gets 90% Acceptances for GBP 7 Billion Raise"](#), Morningstar, 11 April 2024.

¹⁵ ["RPC's Response to the UK Secondary Capital Raising Review Call for Evidence"](#), November 2021, page 6.

¹⁶ ["Further Issues Summary"](#), London Stock Exchange, 31 July 2024, accessed September 2024.

¹⁷ ["National Grid's Investment Proposition"](#), NG, May 2024.

In conclusion, our view is that the RII0-3 regulatory regime should significantly reduce risk for investors, and this should result in a CoE at the bottom of Ofgem's proposed range of 4.57% and 6.35%. This is supported by the market evidence we have described above.

Innovation

Innovation funding is a key pillar of the RIIO framework, allowing networks to go beyond business-as-usual activities to fund innovative solutions for meeting Net Zero, reducing inefficiencies and improving outcomes for consumers. As large amounts of consumers' money is funnelled into innovation, via both the Network Innovation Allowance (NIA) and the Strategic Innovation Fund (SIF), they have a right to know how it is being spent, and how far innovation projects are meeting their aims. With this in mind, we have reviewed how transparent companies are in their Business Plans regarding innovation, as well as how well networks have centred consumers within their work.

Level of information provided

We are pleased to see that across the networks, all Innovation Strategy annexes include details on innovation projects deployed during the RIIO-2 period. This information is crucial in demonstrating the return on consumers' investment in innovation.

Additionally, all companies clearly state the amount of NIA funding requested for the next price control period, either in their Business Plans or annexes.

However, there is an inconsistent level of information in the different company Business Plans. The innovation section in some plans is vague, with most details buried in the Annex Innovation Strategy. The plans should provide enough information for stakeholders to understand the company's RIIO-3 commitments. However, key details, such as which previously proven innovation projects will be deployed, are missing. For example, NGN does not clearly outline this, whereas SPEN does specify the innovation projects planned for the RIIO-3 period.

Many companies have overlooked the SIF in their Business Plans or innovation strategies, with no detail provided on projects planned or how much money they intend to bid for. SSEN is an exception, as it clearly outlines its key priorities for using the SIF funding.

Transparency

Some companies lack transparency in their annexes, particularly regarding deployment costs. WWU details its planned innovation projects, including estimated costs, in its Innovation Strategy annexe. However, SPEN and NGET have not disclosed this information, and NGT does not clearly specify the NIA requested amount for each strategic theme.

Centering customers

Some companies have allocated a disproportionately small portion of their requested NIA funding to explicitly support customers in vulnerable circumstances. For example, WWU has allocated only £1.45 million out of £37.9 million (3.8%) and SGN just £1.3 million out of £30.9 million (4.2%) to addressing customer challenges. In contrast, Cadent has dedicated £8 million out of its £21.24 million (37.7%) NIA allowance to supporting vulnerable customers.

Vulnerability

We welcome collaboration both on a regional basis (such as with the local DNO) and between the GDNs themselves on their vulnerability work, particularly in increasing their PSR reach and implementing successful VCMA projects. We note the positive impact that collaboration has had, as evidenced by the useful and well-presented joint vulnerability strategy. We would like to see more collaboration in the sector, with GDNs viewing the ringfenced 25% as a minimum level, rather than a goal they need to reach. Companies should look for opportunities to scale up their individual projects, and Ofgem should take opportunities to provide more strategic direction for VCMA funding.

Regarding the expansion of projects to the installation of energy efficiency measures, the companies have no existing competency in this area and it therefore would seem inappropriate for GDNs to be undertaking these tasks.. The proposed examples duplicate efforts by other organisations and local authorities. The companies should be signposting to other resources. While it may be beneficial when there is no recourse to other funds, funding these projects does not align to their core role and so risks mission creep.

Independent Stakeholder Groups statements

For the purpose of this consultation, we reviewed the Independent Stakeholder Groups' (ISGs) sections of the network companies' Business Plans. All the Business Plans talked positively about the ISGs, highlighting their beneficial role in the creation of these Plans. The primary feedback indicated that the ISGs scrutinised the Business Plans and provided constructive feedback to hold the companies accountable for their Business Plans' outcomes, stakeholder engagement and customer satisfaction.

However, there was inconsistency in the level of information provided by different companies in the ISG sections of their Business Plans. Some companies offered detailed insights into their ISGs' feedback and how they addressed it, while others provided only general information about the process they followed. NGN is an example of good practice, as they submitted a more comprehensive ISG section compared to the other companies, demonstrating in this way the effectiveness of the ISG's involvement in the creation of their Business Plan. They presented a table outlining the topics that ISG examined, the feedback given and how NGN responded to it, a format which made it easier for us to understand where and how the ISG had commented as well as how NGN reacted to the feedback.

However, we have not been able to assess, and therefore raise a concern, the value that ISGs have added for consumers. For example, all companies have indicated that their business as usual costs will increase, however, based on our review of the ISG statements included in the Business Plans, we are not sure of the extent of challenge that the ISGs are able to provide on this.

Finally, all companies directed readers to other websites and more detailed reports beyond their Business Plans for additional information regarding the contribution and effectiveness of ISGs. As a result, we understood that the network companies did not consider the Business Plans as the sole source for presenting ISG information. We only reviewed the sections on ISGs within the Business Plans, as this was the scope of this consultation.

Sector Specific Issues

Gas Transmission (NGT)

We support NGT's ambition to ensure green gas producers are able to connect to the NTS faster than current timelines. NGT proposes to consider upgrading natural gas assets to hydrogen-ready assets if the cost is similar. This may be a low regrets action should these assets be available. It would also prompt Ofgem to consider how such investments would be monitored and treated within RIIO. Furthermore, it would encourage the hydrogen transport business model to ensure relevant assets, and their investment, are trackable between these two frameworks and that any risk of duplication is mitigated.

We agree that there is a need for more focus on ensuring as close to real-time gas quality information is available. Many changes to network entry agreements are being made to widen the quality of gas entering the system due to changes in the sources of this gas. While ensuring the security of supply is important, the potential risks to CCGT plants and industrial consumers have been noted via the UNC, where they may be particularly sensitive to changes in gas quality. This need for real-time data will only become more important should the NTS flow a hydrogen blend and sensitivity to this change increase.

We also welcome the introduction of Collaborative Visual Data Twin (CVDT) project digital twin. We have seen innovation projects happen already on this so it is important that clear expectations on delivery in the early years of RIIO-3 are set by Ofgem.

Incentives

We are disappointed to see that NGT has provided very little detail on the rationale behind their incentive targets and proposed calibration in the main Business Plan. Key information for understanding these proposed targets, with the exception of the customer satisfaction incentive, is not in the main Business Plan document and instead in an annex nearly the same length as the plan. We believe Ofgem were clear that information supporting companies' targets, rather than simply a statement of what they are, should be visible in the main Business Plan and stakeholders should not rely on other annexes to understand this.

We also note that NGT has given no context of their performance in RIIO-T2 in the main Business Plan for all but one Output Delivery Incentive (ODI) to support justification for the new targets.

For residual balancing, NGT proposes to increase all caps and collars by around 50% even after accounting for inflation. NGT has not explained in the main Business Plan the reason for such an increase. The minimisation of changes to the agreed maintenance plan (Change Scheme) proposes changes to the cap and collar and the introduction of a deadband but without a change in the target. We would expect that additional potential rewards would not be justified for achieving the same target as RIIO-T2.

A target for procurement of NTS shrinkage is not included, making it difficult to assess whether the cap and collar of +/- £5 million is justified, particularly given the change from this being a reputational incentive in RIIO-T2. It is important for consumers that shrinkage is procured as efficiently as possible to minimise this cost for them. However, the main plan does not appear to contain any justification for this proposal and how it would alter NGT's performance in RIIO-T2, which is also not referenced.

We are aware that demand forecasting is important to industry and good performance supports good commercial decisions. Our interpretation of the targets proposed (by increasing the mcm target) that this would loosen the targets on NGT, rather than tighten them. This seems contrary to the views of industry. Again, this change is not explained in the main Business Plan.

We are supportive overall of efforts to reduce NGT's operational emissions. We are aware that the new incentive proposed related to the deployment of recompression units is about deploying units which are already paid for through the price control. There is no evidence in the main Business Plan on how this incentive would alter NGT's behaviour from its current practice of deploying these units. It is therefore not overwhelmingly clear what the benefit of the new financial incentive would be for consumers or that this is the best way to achieve the intended outcome.

Similarly, there is no information in the main Business Plan on the justification for the GHG fugitive emissions and associated target. If incentives are taken forward on emissions, we would encourage Ofgem to think about their naming.

We find that both titles proposed are not intuitive about what the targets aim to deliver and risk ambiguity.

Overall, the information regarding incentives in the main Business Plan is insufficient, with the exception of the customer service incentive.

We welcome the introduction of minimum response thresholds in the customer satisfaction incentive. We have been concerned that the incentive in RIIO-T2 is in some instances based on very low numbers of responses which may not be suitably representative on which to either reward or penalise NGT. It is important that more robustness is achieved in the incentive to ensure that rewards and penalties are justified in RIIO-T3.

We note that incentive targets for customer service areas proposed (ranging from 8.2 to 8.6) sit both slightly below and only slightly above average existing performance in RIIO-T2 (8.49). In two of the 4 years of data reported by NGT, scores have been at or above 8.6. There is a risk that the proposed targets do not stretch the performance already achieved in RIIO-T2.

We do not generally believe that setting targets based on an average of the last five years is a sufficiently ambitious methodology. It does not allow for recalibration around the service level now expected by customers. As we have said in previous price controls, we believe setting targets at a percentile above 50% is a stronger methodology. It gives greater weighting to higher performance and lower weighting to poorer performance. This encourages continual improvement of performance until such point where there are diminishing returns. We would encourage Ofgem to consider such a methodology here, rather than opting for average performance. By its definition, average performance methodologies cannot bank improving performance achieved in the previous price control.

Electricity Transmission

Community benefits

All the TOs included plans for providing community benefits throughout the T3 period. We believe that community benefits should be integrated into the development of new infrastructure, however they should not be justified as a

way to increase community acceptance, with costs allowed to increase in order to reduce legal challenges.

There is a risk in the delivery of community benefits that differing approaches from the companies may result in a postcode lottery, with recipients in some license areas receiving more or less benefits than others for the same level of disruption. While differences may be seen as inevitable due to the delay in firm guidance from the government, we feel there is more that Ofgem could do to encourage standardisation and for the TOs to share learnings and best practice with each other.

One of the biggest differences is between how the companies propose to fund community benefits. While NGET and SPEN propose a UOILI allowance (of £4.8 million and £20 million respectively), SSEN's proposals cover funding through totex, ASTI, LOTI and any other funding available when the government makes a firm decision on its community benefits guidance. Additional sources of funding mentioned include NGET's £6 million 'flexible fund'.

Stakeholder and community engagement is a key pillar of community benefits, ensuring that benefits are targeted for maximum impact. We are encouraged that all plans refer to existing engagement, however there are varying levels of detail. We note that SSEN's projects are focused on themes that were identified as a priority by their stakeholders (skills, culture and alleviating fuel poverty), however information on who the stakeholders are and how they were consulted is missing from the plan. NGET refers to their partnerships schemes, indicating co-creation in their benefits delivery.

SPEN appears to have the most detailed plan, identifying how they have embedded community engagement throughout, with principles that have been developed with their stakeholders. They have also indicated a £3.10 SROI from every £1 spent on community benefits. Going forward we would like to see the TOs work together with a shared SROI model - potentially taking learnings from the model used by Distribution Network Operators (DNOs) and GDNs in their vulnerability programmes - to assess how well their funds are performing to deliver lasting benefits in their regions.

Stakeholder and customer engagement

Of all the plans, NGET appears to have the most developed and comprehensive approach to customer research and stakeholder engagement. We would like to see more coordination between the TOs, potentially with Ofgem oversight, to ensure a consistent approach and that best practice is embedded. Three entirely separate approaches creates more administrative work for the TOs and results in inconsistencies.

Gas Distribution

Customer service

In the second year of GD2 (2020/21), all 8 licence areas exceeded their targets on planned interruptions, unplanned interruptions and connections. We therefore would like to see GDNs strive for stretching targets, and for Ofgem to calibrate the incentive going into GD3 to avoid over-rewarding companies.

Unplanned interruptions

The unplanned interruptions incentive can provide a useful tool in driving GDN performance, and ensuring that customers experience fewer instances of interruptions to their supply, and shorter waits for reconnection.

Ofgem asked the GDNs to propose a common output for non-Multiple Occupancy Buildings (MOBs) and a GDN specific target for average MOBs interruptions. We are pleased to see that all proposed targets are relatively aligned, and that the majority of companies agree that a penalty-only incentive would work best to improve and embed performance standards. We note examples of good practice in collaboration, such as SGN sharing mapping data with third parties, leading to a reduction in the total number of unplanned interruptions, and NGN's proposal to set up a workshop to share best practice with other GDNs. In light of this, we feel it may be best for Ofgem to set a baseline performance level (under which companies would incur a penalty) rather than introduce relative targets.

Disconnections

Ofgem has stated its intention for GD3 to include a new disconnections survey. We are supportive of data collection in this area, due to the potential for

disconnections to increase as consumers decarbonise their home heating. Eventually, the survey results could roll into the ODI-F for customer satisfaction, ensuring that consumers receive a timely and efficient service.

There are disparities in the level of information provided on disconnections across the GDNs. SGN does not mention the disconnections survey or any plans around disconnection customer service, other than to forecast around 1,650 customer-funded disconnections per year. Cadent has a similar forecast, however WWU predicts that by 2032 it will be carrying out 4,000 disconnections each year.

Commitments to improving the customer experience for disconnections vary. Cadent intends to work collaboratively with the HSE and Ofgem to determine the policy framework, while NGN and WWU have made more specific plans, with NGN referring to 'enhanced voluntary service improvements' on disconnections once baseline results from the survey are available, and W&W will evolve its connections platform, including an app tracking engineer visits and troubleshooting AI, to deal with disconnections. While we accept that it is difficult for GDNs to precisely plan the extent of disconnections while the policy environment is changeable, it is important for the companies to anticipate future trends in order to best serve their customers.

Hydrogen

All companies emphasised that there is uncertainty around the future of gas, and it is unclear what will happen in the long term. Some companies have independent documents addressing this issue, for example Cadent has published their 'Future of Gas Networks' report.

Companies have also set plans to support the energy transition. They aim to pursue low-regret innovation and development to support decarbonisation, such as biomethane, hydrogen blending and hydrogen for industrial use. In the RIIO-GD3 framework, they stated that they will continue to deliver a safe and reliable gas network for their customers under a 'business-as-usual' approach while carrying out new and proportionate initiatives to prepare their network for an affordable, positive and fair transition to net zero.

We reviewed whether any hydrogen projects were announced to receive funding through the RIIO3 framework. In this context, network companies stated that

Ofgem will not provide funding for dedicated net zero-related upgrades during this period through RIIO3 funding. As a result, the companies must use alternative sources to finance their hydrogen-related activities.

Cadent

Cadent's Business Plan evaluates how to support effective whole system planning across various potential futures, including green gas connections such as biomethane, repurposing for hydrogen, and the substitution or disconnection for electrified heat solutions. They also aim to promote and accelerate the growth of domestic biomethane and hydrogen blending production markets.

NGN

Their RIIO-GD3 plan focuses on low-regrets investments, including hydrogen blending, network sectorisation for future repurposing or decommissioning, and the development of broader skill sets to support the Regional Energy Strategic Plan (RESP). However, they acknowledge that due to uncertainties in costs and deliverability, additional investigations are necessary to establish a credible case for implementation. To explore future net zero opportunities, such as hydrogen blending and the use of hydrogen for industry, NGN will use UIOLI funding streams, uncertainty mechanisms and reopeners.

SGN

During the first two years of GD3, SGN aim to complete gathering evidence for hydrogen blending. They aim to prepare their network for accepting blended hydrogen to supply customers. Their early-stage hydrogen blending development work is currently being funded through the Network Innovation Allowance (NIA) and will be progressed through the NZARD and NZASP routes for pre-production.

WWU

Their desired outcomes by the end of RIIO-GD3 is to understand where they need to prepare the network for repurposing for hydrogen, support hydrogen blending and be ready to roll out plans for hydrogen heating if that policy decision is made. They are not asking to invest in making assets hydrogen-ready in RIIO-GD3.

To fund innovation for the future of the energy networks, they plan to use a combination of Network Innovation Allowance (NIA) and the Strategic Innovation Fund (SIF), depending on the challenges and opportunities that emerge through RIIO-GD3. They also intend to use NIA in combination with other funding sources e.g. Net Zero Re-opener Development UIOLI Allowance (NZARD UIOLI).

WWU have followed the guidance set out in Ofgem's Sector Specific Methodology Consultation and will be seeking alternative funding outside of RIIO-GD3 for major hydrogen related projects. They will also continue to explore and develop technologies and techniques which could help prepare and deliver reuse of existing gas network assets.

Our conclusions and recommendations for Ofgem

Ofgem's RIIO-3 price controls for gas networks and electricity transmission are due to commence in April 2026, and these network companies submitted their Business Plans to Ofgem in December 2024. Ofgem has invited stakeholders to submit evidence about these plans for them to consider before draft and final decisions are made later in 2025. In this response we have examined whether the RIIO-3 regulatory regime and company Business Plans are offering value for money for consumers across the following areas:

- Totex and cost efficiency
- Outputs and incentives
- Financial returns

We also make recommendations for Ofgem to consider in their assessment of company Business Plans prior to the draft and final determinations for RIIO-3.

Totex assessment

Gas distribution

The aggregate totex bid for the 5 years of GD3 across all companies is £16.3 billion, a 19% or £2.6 billion increase on their GD2 forecasts of £13.7 billion. Repex cost forecasts increase by over 30% for NGN, SGN, and WWU. Cadent do not provide a breakdown of their costs. Our assessment of their totex bids concludes:

Iron mains replacement: the main reason given for the increase is increased repex costs to address the safety mandated iron mains replacement programme. All GDNs are forecasting higher repex costs and claim that iron main replacement is becoming more complex and costly at the end of the programme. We are concerned that companies have benefited from cheaper delivery costs in earlier price controls and are now inefficiently asking customers to pay for higher costs.

Ongoing efficiency: each company has proposed an ongoing efficiency of 0.5% per annum. We do not consider the 0.5% annual target to be particularly ambitious and recommend 1% instead.

Additional asset replacement: some companies have claimed that additional work will be required, much for mandatory requirements. We are concerned whether these claims are new mandatory activities or if expenditure has simply been deferred from prior price controls.

Uncertainty mechanisms: it is difficult to ascertain the triggers and value of uncertainty mechanisms from most company plans. Some plans are unclear about what costs are in the baseline totex bids. We are concerned that some plans have a large element of totex assigned to uncertainty mechanisms, thereby transferring risk to customers.

Overall, we are concerned that the sector is seeking substantial increases in totex allowances. This is occurring in a sustained period of declining gas demand and near completion of the gas main replacement programme which should enhance safety and resilience.

Gas distribution - recommendations

Expenditure drivers: It does not seem credible that GDNs should receive above inflation totex increases at a time of declining gas demand and decreases in new customer connections. Ofgem should assess and ensure that allowances are more proportionate to usage volumes.

Iron mains replacement: we are concerned that allowances may have already been awarded for this work. Ofgem should assess and disallow expenditure bids where they are inefficient or have already been funded.

Ongoing efficiency: we consider the ongoing efficiency target should be at least 1% per annum, consistent with the RIIO-2 levels.

Uncertainty mechanisms: we are concerned that the scale and triggers for cost uncertainty mechanisms are either unclear or pass additional risk to customers. Ofgem should ensure that uncertainty mechanisms are only applied where the company is clearly unable to manage the risk.

Gas transmission

The NGT totex bid for the 5 years of GT3 is seeking an overall increase of £720 million (22%) above the GT2 5-year allowance. The plan also identifies an additional £1.3 billion of uncertainty mechanisms, representing a 63% increase from GT2 levels. Our assessment of their totex bids concludes:

Capex forecasts: NGT forecast that capex will need to increase by around £300 million - 400 million above GT2. This includes a range of asset health, compressor modifications, decarbonisation and cyber/physical security costs. No load related capex is expected as no new connections are expected in GT2. The plan provides little information about why these cost increases are needed.

Opex forecast: NGT forecast that opex will also need to increase by around £300 million - 400 million above GT2. This includes both direct network operating costs and indirect support costs. Activities include preparing for hydrogen blending on the gas network. Again, little information is provided about why these increases are needed.

Ongoing efficiency: NGT has proposed efficiencies of 1.5% over the 5-year GT2 period. We do not consider this target to be particularly ambitious.

Uncertainty mechanisms: the £1.3 billion is broken down into asset health, compressor emissions and system efficiency. Again, it is unclear why and when they may be triggered and whether the proposed costs are efficient. We are concerned that these uncertainty mechanisms simply transfer risks the company can best manage to customers.

As for gas distribution, we are concerned about NGT's bid for substantial increases in totex allowances. This is occurring in a sustained period of declining gas demand and closure of gas-fired power stations.

Gas transmission - recommendations

Expenditure drivers: It does not seem credible that NGT should receive above inflation totex increases at a time of declining gas demand and closure of gas-fired power stations. Ofgem should assess and ensure that allowances are more proportionate to usage volumes.

Capex and opex increases: we are concerned that allowances may have already been awarded for this work. Ofgem should assess and disallow expenditure bids where they are inefficient or have already been funded.

Ongoing efficiency: we consider the ongoing efficiency target should be at least 1% per annum, consistent with the RII0-2 levels.

Uncertainty mechanisms: we are concerned that the scale and triggers for cost uncertainty mechanisms are either unclear or pass additional risk to customers. Ofgem should ensure that uncertainty mechanisms are only applied where the company is clearly unable to manage the risk.

Electricity transmission

According to our analysis, the increase in baseline totex for ET3 totals some £38 billion, a 76% increase over ET2. If uncertainty mechanisms for additional expenditure were to be triggered, then this could potentially increase to some £85 billion, almost a four-fold increase from ET2. Also, we note that these plans have been developed in advance of the Government's Clean Power 2030 plan and the forthcoming NESO spatial plan, which may cause further increases. Our assessment of their ET3 totex bids concludes:

Understanding ET2 totex performance: revised ET2 price control totex allowances and outturn performance should define the starting point for ET3, but there is little clarity from Ofgem or companies on the current position. ET2 plans have changed significantly from the ASTI programme and agreed other uncertainty mechanisms e.g. our analysis of ET2 totex to date indicates that NGET and SPT are currently underspending by c20% but this falls to near zero after enduring value adjustments.

ET3 load related expenditure: vast increases are proposed but supporting evidence to assess and compare value for money is limited - neither NGET nor SHET has published Business Plan data tables, and SPT information is limited. For example, it is unclear whether projects approved under the ET2 and ASTI programmes have experienced cost increases, and whether the need and costs for new projects are justified.

Efficiency of ET3 non-load expenditure: the SSEN and SPT plans appear to seek significant commensurate increases in non-load capex and opex expenditure

alongside load related capex. We are concerned that this is unjustified until major construction projects are completed.

Uncertainty mechanisms and price control deliverables: the scale of proposed ET3 uncertainty mechanisms (£40 billion) even exceed the ET3 baseline bids. We recognise the importance of uncertainty mechanisms for large uncertain reinforcement projects. Project-based deliverables should add incentives to ensure cost efficient and timely delivery. We are concerned that such expenditure simply becomes a cost pass through as companies can justify ongoing internal and external cost increases, potentially undermining the entire RIIO incentive-based totex regime.

Delivery risk: we are concerned that the dramatic scaling up of transmission totex across the three TOs increases the risk to consumers of both inefficient costs and delayed delivery.

Electricity transmission – recommendations

Understanding the ET3 totex foundation: we recommend Ofgem assesses and publishes consistent ET2 totex performance information. This should provide useful transparency about the starting point for the ET3 totex regime.

Load related expenditure: little information is provided in plans to justify this expenditure. Ofgem should ensure this information is quickly published on a consistent basis to enable external scrutiny of such major claims.

Non-load expenditure: Ofgem should carefully scrutinise whether claims for increases in non-load or residual costs are justified. Ongoing efficiency targets should still be applied to these costs.

Uncertainty mechanisms: a vast amount of ET3 expenditure is likely determined through flexible uncertainty mechanisms, passing additional risk to customers and potentially undermining the totex incentives across the price control. Ofgem should carefully review the design of the ET3 uncertainty mechanism and totex incentive framework to ensure it delivers value for money for consumers.

Delivery risk: as noted above, some plans do not include much detail about delivery of major capital plans. We suggest Ofgem assess whether each of the companies has demonstrated the capability to deliver an accelerated capex

programme of such scale within the time specified. Accelerating the introduction of competition for asset delivery should be strongly considered as an alternative.

Business Plan incentive

Ofgem's BPI rewards companies through three stages. These are: A) providing sufficient information to set the price control effectively, B) adequately justifying costs and their efficiency, and C) rewarding the overall quality of the Business Plan.

We have reviewed the information published by the companies which varied considerably. As well as a main plan, companies were invited to produce supporting detail to support their plans. One such key supporting element is the individual Business Plan data tables which allow all elements of Business Plans to be assessed and compared.

Based on the public information we have reviewed; NGN has published the most evidence to support their plan e.g. full Business Plan data tables; next are WWU, NGT and SPT e.g. they have also published full or partial data tables; SHET, NGET and Cadent have provided the least evidence.

Recommendation

In our view, only NGN has clearly provided sufficient information to merit a stage A incentive under the BPI.

Customer bill impact

Each of the company plans included information on the impact their plans will make on customer bills. Customer bills will be impacted by a range of factors including totex increases, rates of return and changes to depreciation policy. There are significant differences between these forecasts, apparently because different calculation approaches and assumptions have been used.

Recommendation

We recommend that Ofgem clarifies these forecasts and publishes the proposed individual and combined impacts on a consistent basis. We suggest that this analysis shows the cumulative impact on consumer bills over time.

Financial considerations

Our review of Business Plan submissions on financial issues focused on two issues, the regulatory depreciation of gas networks and the Cost of Equity (CoE).

Regulatory depreciation

Future usage of gas transmission and distribution networks is expected to decline rapidly. Currently, these assets are depreciated over 45 years, and the network companies face a risk of asset stranding. To mitigate this risk. Ofgem proposes to apply accelerated regulatory depreciation, potentially 20 years instead of 45 years. This would increase customer bills in the short term.

The gas network companies argue for longer depreciation periods based on their view that networks will be needed post 2050, and for higher returns as there is a greater stranding risk. We consider its not appropriate or necessary to increase allowed returns in compensation for an investor perception of increased risk. We aren't convinced that the gas network needs to be fully depreciated by a certain date and that customers should be paying for this.

Recommendation

We recommend that Ofgem explore other solutions to address the perceived gas network stranding risk that has a lower impact on current and future customer bills.

Cost of equity

Ofgem's sector methodology proposed a CoE range of between 4.57% and 6.35%, with a midpoint of 5.46%. The network companies have made proposals ranging from 6.3 %to 6.9% in their Business Plans, arguing that they face higher risks and Ofgem's methodology is incorrect.

We do not agree with these company positions. We are concerned that Ofgem's approach for RIIO-3 places undue reliance on the established positions of regulated companies and will result in overgenerous returns. We do not accept company claims that equity risks increase for RIIO-3. Our view is opposite to this. We have updated Ofgem's own market cross checks which suggests a more appropriate cost of equity would be 4.1%. National Grid's successful rights issue further demonstrates the attractiveness of Ofgem's current regulatory regime.

Recommendation

We recommend that Ofgem considers our market evidence to set a cost of equity at the lower end of its proposed range.

Innovation

Ofgem should require network companies to provide standardised and consistent Business Plans and annexes, detailing cost breakdowns for innovation projects, NIA funding per strategic theme, and which previously proven innovations are being implemented. Additionally, Ofgem should encourage greater investment in innovation projects that directly benefit consumers. These measures will enhance transparency, accountability, and strategic alignment, ensuring a fair and effective approach to innovation funding in the RIIO-3 period and beyond.

More specifically, we would like to see the companies strengthen their innovation submissions by:

- **Enhancing transparency on deployment costs.** Companies should ensure that their Business Plans and annexes outline the estimated costs for deploying innovation projects. This transparency will help stakeholders better understand each project's financial implications and return on investment.
- **Allocating sufficient NIA funding to vulnerable customers.** GD companies should allocate a more proportionate share of NIA funding to address the challenges faced by vulnerable customers, ensuring these initiatives receive the necessary support.
- **Improving consistency and clarity in innovation plans.** Innovation sections in Business Plans should be more comprehensive and consistent, clearly outlining the company's commitments for the RIIO-3 period. Essential details, such as previously proven innovation projects and NIA funding requested for each strategic theme, should be included both in the main plan and annexes for better clarity and transparency.

Vulnerability

Our main recommendation is that Ofgem sets the VCMA allowance for the GDNs at a lower level than the inflated total in GD2 (after the FPNES scheme, including volume driver targets, rolled up into the allowance). It should review the GDNs' vulnerability plans in light of this, assessing their preparedness for winding down or scaling back projects with the least impact on the customers they support.

Additionally, we maintain that Ofgem should stick carefully to its GD2 determination that gas networks' role in vulnerability should remain in the remit of their 'existing areas of competence, activity and consumer interaction'. This should naturally rule out any projects in the company business plans that include the installation of energy efficiency measures. It should also provoke Ofgem to review its thinking on whether 'enabling a just transition' should be applicable to the GDNs' vulnerability regulation.

ISG Statements

ISGs were found to be beneficial and helpful but we raise a concern about how well their effectiveness has been demonstrated: All companies acknowledged that ISGs were a valuable component of the process and that their scrutiny and feedback significantly improved the development of their Business Plan. It is essential for network companies to maintain high standards for consumer outputs and, according to the network companies' feedback, ISGs' contribution was reported as crucial for improving performance and ensuring consumer satisfaction. However, it was not possible from the information provided within the Business Plans to scrutinise their outputs and the value added.

Improve ISGs' reporting consistency across all companies. We believe that the ISG sections in Business Plans should be more consistent across all companies and provide sufficient information to clearly demonstrate how and on which topics the ISG provided feedback. This approach will help the readers gain a deeper understanding of the actual impact and effectiveness of the ISGs' contributions during the Business Plan development process, rather than just stating their effectiveness without providing examples.

Sector specific issues

Gas Transmission

Ofgem should focus more on ensuring as close to real-time gas quality information is available. This need for real-time data will become more important if the NTS flows a hydrogen blend and sensitivity to this change increases.

Incentives

We are supportive overall of efforts to reduce NGT's operational emissions. We are aware that the new incentive proposed related to the deployment of recompression units is about deploying units which are already paid for through the price control. However, there is no evidence in the main Business Plan on how this incentive would alter NGT's behaviour from its current practice of deploying these units. It is therefore not clear what the benefit of the new financial incentive would be for consumers or that this is the best way to achieve the intended outcome, hence, we would encourage Ofgem to clarify those points.

Furthermore, if incentives are taken forward on GHG fugitive emissions and associated targets, we would encourage Ofgem to think about their naming. We find both titles are not intuitive about what they aim to deliver and risk ambiguity.

Finally, we do not generally believe that setting targets based on an average of the last five years is a sufficiently ambitious methodology. It does not allow for recalibration around the service level now expected by customers. As we have said in previous price controls we believe setting targets at a percentile above 50% is a stronger methodology. It gives greater weighting to higher performance and lower weighting to poorer performance. This encourages continual improvement of performance until such a point where there are diminishing returns. Therefore, we would encourage Ofgem to consider such a methodology here, rather than opting for average performance. By its definition, average performance methodologies cannot bank improving performance achieved in the previous price control.

Electricity Transmission

Ofgem should embed competition into the building of future assets before agreeing to allocate all agreed costs in the business plans. It should review the balance of costs between baseline allowances and uncertainty mechanisms, as well as encouraging standardisation of the breakdown of costs so that the overall impact on totex (and customer bills) can be consistently assessed.

Community benefits

Ofgem should work to encourage collaboration and standardisation between the TOs on the delivery and funding mechanisms involved in community benefits. While it may be appropriate to wait until the promised government guidance is published in Spring 2025, Ofgem should consider what actions it can take if there are delays to the timeline going into RII0-T3.

Stakeholder and customer engagement

Ofgem should encourage a standardised approach to stakeholder and customer research, avoiding duplication across the TOs.

Gas Distribution

Customer service

We would like to see GDNs strive for stretching targets, and for Ofgem to calibrate the incentive going into GD3 to avoid over-rewarding companies.

Unplanned interruptions

The unplanned interruptions incentive can provide a useful tool in driving GDN performance, and ensuring that customers experience fewer instances of interruptions to their supply, and shorter waits for reconnection.

Ofgem asked the GDNs to propose a common output for non-Multiple Occupancy Buildings (MOBs) and a GDN specific target for average MOBs interruptions. We are pleased to see that all proposed targets are relatively aligned, and that the majority of companies agree that a penalty-only incentive would work best to improve and embed performance standards. In light of this, we feel it may be best for Ofgem to set a baseline performance level (under which companies would incur a penalty) rather than introduce relative targets.

Disconnections

There are disparities in the level of information provided on disconnections across the GDNs. Ofgem should start considering how to encourage the best possible data collection on disconnections, including GDNs sharing their working, and explore the potential for disconnections to be included as part of the overall customer satisfaction incentive.

Hydrogen

Ofgem needs to address the uncertainty around the future of gas and the gas networks. They also need to make sure that the role of the gas network in net zero transition is maximised by making progress with low-regrets opinions consistent with government policy. The network companies anticipate that Ofgem will facilitate the preparatory activity, through a combination of innovation stimuli which can respond to government decisions on hydrogen and heating.

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