British Gas
Looking after your world

Legal & Regulatory
Lakeside West
1st Floor
30 The Causeway
Staines
Middlesex
TW18 3BY
t: 01784 494000
f: 01784 878719

Rachel Fletcher
Partner, Distribution

Hannah Nixon
Partner, Transmission

By email to: RIIO.GD1@ofgem.gov.uk and RIIO.T1@ofgem.gov.uk

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Dear Rachel and Hannah,

Consultation on strategy for the next gas distribution price control (RIIO-GD1) and transmission price control (RIIO-T1)

1. Thank you for the opportunity to respond on Ofgem's proposed strategy for the next price controls for gas distribution (RIIO-GD1) and gas and electricity transmission (RIIO-T1). As a large integrated energy company in Great Britain that does not own any network interests, Centrica is in a key position to provide an unconflicted perspective on the critical issues that need to be addressed during both RIIO-GD1 and RIIO-T1.

2. This response is submitted on behalf of the Centrica Group of companies, excluding Centrica Storage, and is not confidential. We have structured our response as follows:

    - This covering letter highlights what we see as the key issues across both the RIIO-GD1 and RIIO-T1 price controls. We have grouped these into **joint issues** affecting both transmission and distribution (T&D), such as financing and uncertainty; **transmission issues** such as anticipatory investment and connections; and **distribution issues** such as the gas mains repex programme and shrinkage.
    - Appendices 1, 2 and 3 provide more detailed commentary regarding our views on the joint issues, transmission issues, and distribution issues respectively.
    - Finally, Annexes 1 and 2 contain supporting papers by Cambridge Economic Policy Associates (CEPA) in relation to Financing and Uncertainty respectively.

Key Messages

3. Transmission and distribution charges account for over 20% of the average customer's bill, and this share is set to rise over time given the huge investments needed to decarbonise and modernise our industry. Centrica alone spends over £2 billion each year on transmission and distribution charges across our supply, generation, and shipping business, and £1.5 billion of this will be reset by this price control process from April 2013. At this time of acute sensitivity about the energy bills faced by householders and businesses it is critical that this process delivers the best possible outcome in terms of value for money for customers. This means network investment plans that are aligned with the government's targets for delivering a low carbon energy sector while also ensuring that network company risks and rewards are commensurate with the performance they deliver.

4. We welcome the focus in RIIO on encouraging the networks to be more innovative and responsive to user requirements so that they deliver outputs that stakeholders value in a timely manner. We have seen some initiatives, mainly from NG, to engage better with their

users. However, Ofgem has a massive challenge to ensure that, in this first round of controls under the new regime, it strikes the best deal available for customers.

5. We are in particular concerned that the timeframes for some key decisions may be unduly compressed to meet the requirements of fast-tracking. We recognise some of the potential benefits of fast-tracking. From a user perspective, it potentially gives us earlier visibility of the outlook for charges. However, as with any new complex process, if mistakes are made they could turn out to be very costly given the long-term nature of the new price controls. The best protection Ofgem has to avoid mistakes is, consistent with the spirit of RIIO, to ensure the maximum opportunity for stakeholder input and consultation. There is a clear trade-off here between the benefits of fast-tracking and the benefits of deeper stakeholder engagement, and on balance we are convinced that the requirements of effective consultation and engagement must come first. It is not yet proven that the new process is working sufficiently well to make fast-tracking an option that is a clear potential benefit to networks and customers.

6. We accept that part of the new process is potentially more uncertainty for networks over their revenues dependent on timing and approval of their project. Ofgem's proposed framework for networks to address these uncertainties is therefore reasonable. However, Ofgem has failed to adequately recognise the increased volatility in charges that will inevitably be associated with protecting networks from increased revenue uncertainty. Ofgem must set up a workstream that addresses the wider market implications of its price control processes, and produce a framework that helps to manage the increased volatility that will otherwise result. CEPA has developed a paper for Centrica that explains precisely how Ofgem can do this.

7. At a time when government and Ofgem are reviewing the retail market and looking to remove barriers to entry to the supply market, charging volatility is an area that requires attention. Price control adjustments can have a significant impact on network charging volatility. This in turn imposes major risks on suppliers, whose margin forecasts can be eroded or made worthless if they fail to correctly anticipate the network costs they will have to recover from their customers. Charging volatility has recently been highlighted as a deterrent to new entry in the market by Frontier Economics in a report prepared by Energy UK[1]. Lack of charging stability is a particular issue for small suppliers.

8. The rest of this letter summarises the key points from the rest of our submission. There is a wide range of policy issues that Ofgem must manage through this process. While Ofgem has made a good start in some respects in translating the RIIO concepts into practical proposals, we see scope for significant improvements to the benefit of customers across the board.

Joint transmission and distribution issues

Financing

9. Ofgem's decisions on financing issues will be a key determinant of the overall cost to consumers of the outputs delivered under the price control. As already noted, a key principle of RIIO is that network companies should take greater responsibility for managing their own financing requirements including via new equity if required. We are pleased to see that the majority of Ofgem's proposals are aligned with this principle. However, there are several areas where Ofgem could do more to sharpen incentives on networks and deliver cost savings to consumers:

   - **cost of equity** – we agree with the general approach that Ofgem has taken to estimating the cost of equity. However, Ofgem's assumption on the upper bound

[1] See http://www.frontier-economics.com/europe/en/news/1050/

of the cost of equity range is high by comparison with relevant benchmarks[2], including analysis undertaken by its own consultants[3]. This range should be narrowed going forward unless network companies can provide strong justifications to the contrary.

- **cost of debt indexation** – we strongly support the proposal to index cost of debt based on a trailing average of forward interest rates for corporate bonds. This will ensure that network companies face a real market price for debt financing. Analysis by CEPA as well as recent comment from the City suggests that the proposals should deliver significant cost savings to consumers through the reduction of 'headroom', while also protecting companies from unexpected increases in the cost of debt.
- **pensions** – we remain concerned that energy customers are exposed to greater costs and risks than in other regulated industries, particularly in relation to deficit repair. The Government Actuarial Department (GAD) review of pension scheme funding is an important step forward, but to ensure a good outcome for consumers it is important that benchmarking is undertaken by comparison with the wider commercial marketplace, with funding targets set at a level that is no more generous than the market median.
- **transitional arrangements** – as highlighted above, we do not see a need for transitional arrangements in relation to issues such as the capitalisation of gas repex or changes to electricity transmission asset lives. Network companies should be expected to manage such issues using the financing mechanisms at their disposal unless they can present compelling evidence to the contrary.

Uncertainty mechanisms

10. Meeting the challenges to the industry over the coming years will require network companies to manage substantial uncertainty around what needs to be built on their networks, how and when. Effective decision-making in this context requires that risks be allocated to those able to manage them most efficiently, whether that be network companies, network users, or consumers.

11. Under RIIO it is primarily the networks' responsibility to propose and justify the mechanisms they require to manage uncertainty via the business plan development process. However, Ofgem has suggested a number of potential areas in which mechanisms may be needed.

12. We are concerned that while the individual uncertainty mechanisms may be reasonable in isolation, little account has been taken of the cumulative 'top-down' impact of these mechanisms on network charging volatility. Excessive volatility creates additional risks for energy suppliers, particularly if they are to offer customers a choice of stable long-term tariffs. Analysis undertaken for us by CEPA suggests that under a range of hypothetical scenarios, a gas supplier would need to build a 5.5% - 6.5% implied risk premium into its forecast gas distribution costs over the eight-year price control in order to manage this risk.

13. Charging volatility can be mitigated by network companies relatively easily through mechanisms such as 'logging up' of changes to revenue allowances, reprofiling, and caps and collars. If properly designed, these mechanisms can be made financially neutral to network companies while delivering real benefits for consumers. We would expect to see

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[2] For example, the Competition Commission's decision on Bristol Water, and the Bank of England's December 2010 report.

[3] See Europe Economics, *The WACC for Ofgem's Future Price Control*. This report recommends a range of 3.9 – 5.2% although then raises this to 4.0 – 5.5% "resolved to 0.5 intervals".

network companies taking this issue seriously and putting forward options to address it in the course of the stakeholder engagement process on their well-justified business plans. We ask Ofgem to consider chairing a specific workstream or workshop to help to coordinate views of interested parties on this issue, and factor these views into the business plans of the networks.

Innovation

14. One of the key drivers for RIIO was the need to encourage network companies to innovate and invest for the longer term in order to address the challenges posed by the transition to a low-carbon future. This is a particular issue for electricity networks but there are also important implications for gas, for example in relation to the potential role of biomethane. We therefore welcome Ofgem's proposals to introduce an innovation stimulus fund for both electricity and gas networks under RIIO-GD1 and RIIO-T1, building on the success of the Low Carbon Network (LCN) fund for electricity distribution. To maximise the benefits of these funds to consumers, a number of design issues will need to be addressed, including:

    - **open access** – we welcome Ofgem's proposal to allow access to innovation funding by all licensed energy companies, so that non-network companies can take a lead role in consortia bids. As you know, Centrica was involved in a successful bid under the LCN together with CE Electric, and we are keen to participate fully in the new funding regimes.
    - **clear and transparent funding criteria** – to minimise administrative burden, the Terms of Reference for the innovation stimulus funds should be as clear as possible. This will ensure that companies do not spend time preparing bids that are unlikely to be considered for funding.
    - **additionality and scope of funding –** innovation stimulus funding will only be of benefit to consumers if it facilitates projects that would not have been undertaken otherwise. With this in mind, we agree that it makes sense to focus the funding on projects that promote a low-carbon future. Projects that relate to general cost-effectiveness will benefit network companies directly and should be funded from within baseline revenues.

Transmission Issues

15. Transmission investment over the period of the next price control will be key to ongoing supply security and the achievement of the 2020 targets. It is therefore critical to strike the right investment balance both from a consumer perspective and to reflect the broader government objectives for GB going forward.

16. In electricity transmission this means that the networks must carry out sufficient anticipatory investment to support the changing usage of the network. The major risk here is that underinvestment in electricity transmission will lead to rising constraint costs (and potentially rising wholesale energy prices), which will ultimately flow through to consumers.

17. Ofgem will need to develop much clearer proposals for how these arrangements will facilitate anticipatory investment by the electricity TOs. In the light of the likely severe consequences of inadequate investment in electricity, Ofgem's current thinking requires further development. The lessons of the ENSG process are that there may be a need for a more managed process to ensure investment priorities are identified, reviewed and approved in a timely way. We question whether an output relating to anticipatory investment should in fact therefore be a primary deliverable and whether the "boundary expansion" approach is appropriate. We understand the desire to empower the networks to lead these investment approval processes. However the process established must be fit for purpose and reflect the high costs to all users and customers of any failure to take important decisions in a timely way. This may involve additional cost benefit analysis by Ofgem, as well as greater transparency of business plans, to ensure the right approach for customers.

18. This approach of greater transparency must also extend to gas transmission, both around investment plans and capacity baselines. If baselines are to be used as a key measure of gas transmission outputs, there needs to be a clear definition of what they represent and a thorough, transparent review for consistency with the proposed definition. While we continue to press for improvements in information provision, as part of RIIO Ofgem must insist on full transparency of information to support informed stakeholder engagement.

Distribution Issues

19. The gas mains repex programme is the largest category of expenditure under the current gas distribution control and is responsible for around 20% of the gas distribution charges our retail customers pay. It is critical that this money is spent in the most cost-effective way to ensure the safe transportation of gas. We therefore welcome the HSE's decision to bring forward its planned review of the repex programme to coincide with the RIIO-GD1 price control consultation.

20. To assist with the review, we recently commissioned a piece of cost benefit analysis from Frontier Economics[4]. Frontier's work suggests that the incremental costs of the HSE repex programme may outweigh the incremental benefits by over £400m – a significant concern in terms of value for money to customers. There could be material benefits to consumers from moving to an incentive regime that rewards networks on the basis of reductions in measured iron mains risk, rather than on the length of mains pipe replaced as at present.

21. Another key point to note in relation to value for money in gas distribution is that RIIO-GD1 should be the control at which the majority of the benefits are realised from the GDN sales in 2004 (originally estimated by Ofgem at between £80m and £225m)[5]. We have concerns that the forward-looking focus of Ofgem's cost assessment under the new RIIO model could lead to some of these gains being overlooked. We therefore urge Ofgem to undertake robust comparative benchmarking of historic costs to complement its forward-looking assessment of GDN business plans, and to quantify wherever possible the specific gains to consumers that have been achieved through the DN sales process.

22. Finally, we agree with many of Ofgem's proposals in relation to the output and incentive framework for gas distribution, but further work is needed on the following:

    - **Network reliability and LDZ offtake** – The number and volume of offtake measurement errors has increased exponentially in recent years. We advocate the introduction of specific output / incentive measures on GDNs to address this issue. Our initial thoughts on the design of such measures are discussed in Appendix 2.

    - **Gas shrinkage** – there is scope for significant improvement in the current shrinkage regime to better address leakage from the network 'in the round'. We fully support the use of actual shrinkage data in future controls once smart meters are introduced. In the meantime we expect GDNs to update the existing shrinkage survey and to move forward on issues of upstream theft and unregistered sites (see below).

    - **Upstream theft and identification of unregistered sites** – GDNs currently lack incentives to address these issues under the shrinkage regime. The suggestion to introduce a Code of Practice for unregistered sites is welcome, but there is also a strong case for introducing a focused financial incentive and / or specific regulatory obligations in this area. Again, our thoughts on this issue are set out in Appendix 2.

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[4] See http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/WorkingGroups/Documents1/Frontier%20repex.pdf

[5] Figures quoted are NPV basis, 2004 prices. The majority of these benefits were anticipated by Ofgem to flow through to customers by the time of the second control – see *Potential sale of gas distribution networks businesses: Final Regulatory Impact Assessment*, Appendix 6, November 2004, Page 51.

- **Xoserve** – the organisation will need to play a significant role over the next price control period, particularly in relation to the delivery of smart meters. The performance of xoserve in facilitating industry change is sub-optimal at present. For this to improve suppliers need to be given more influence and control over the governance process and networks need to increase transparency around their change plans.
- **Biomethane / distributed gas** – we agree with the proposal to extend connection standards and introduce reporting requirements for biomethane but without specific incentives attached. The Government's Renewable Heat Incentive (RHI) is the appropriate mechanism for providing direct financial incentives in this area.

23. We hope that the comments set out in this submission have been helpful, and we would be very happy to discuss them in more detail if you would find this useful. We look forward to working with both Ofgem and the network companies over the coming months to refine the proposals set out in the strategy consultation.

Yours sincerely,

Tim Dewhurst

Head of Network Regulation and Market Design

British Gas

APPENDIX 1 – JOINT TRANSMISSION AND DISTRIBUTION ISSUES

1. This section of our response provides more detailed commentary on issues that are common across both the RIIO-GD1 and RIIO-T1 consultations. Specifically, we discuss:
   - financial issues;
   - pension costs;
   - uncertainty mechanisms and risk allocation;
   - capex and opex assessment;
   - funding for innovation; and
   - process issues and stakeholder engagement.

Financial issues

2. In this section we set out our views on the key financial issues in the strategy consultation documents. We comment specifically on:
   - cost of debt indexation;
   - cost of equity parameters;
   - notional gearing; and
   - asset lives and depreciation.
3. We have also commissioned a piece of analysis from CEPA regarding these issues. This is included in Annex 1 to this response.

Cost of debt indexation

4. We fully support the principle of setting the cost of debt on the basis of an indexed long-term trailing average of forward interest rates. This will ensure that networks are only allowed a cost of debt consistent with prevailing market rates. This proposal is in line with the RIIO principles and with regulatory best practice in other EU jurisdictions. This proposal will lead to material benefits for consumers (who no longer need to pay a risk premium to networks to allow for uncertainty over movements in cost of debt over the control), as well as for networks (who are no longer required to manage a material source of risk).
5. Ofgem's proposal to use BBB and A rated bonds as the basis of the index is a sensible and transparent approach, which should provide a high degree of certainty to network companies while also delivering cost savings to consumers. We agree that there is no need for a separate allowance for debt transaction costs, as evidence presented in the CEPA paper suggests that efficient NWOs are typically able to issue debt at a lower cost than the average of the above index.

Cost of equity parameters

6. We support Ofgem's overall approach to setting the allowed cost of equity using the Capital Asset Pricing Model (CAPM). In particular we believe that consumers will benefit considerably from the use of market data as a cross-check (especially from transactions). We consider this to be a more robust approach than the heavily assumption-driven Dividend Growth Model (DGM).
7. In terms of the specific ranges suggested by Ofgem for the different components of the cost of equity, our views are as follows.
   - On the **risk-free rate**, market evidence and the CC's Bristol Water decision supports the proposed initial range of 1.4 - 2.0 per cent.

- On the **equity risk premium**, Ofgem needs to do more to justify its proposals regarding the upper end of the range. In our view an ERP of 5.5% is not supported by either evidence or regulatory precedent such as the CC's Bristol Water decision[6]. While Ofgem cites 'economic uncertainty' as the primary rationale for a higher upper bound, we do not consider this to be an adequate rationale, since the ERP reflects the opportunity cost of different forms of investment (e.g. cash vs debt vs equity) and the current economic uncertainty is likely to affect all of these in a similar way.

- Finally, on the **equity beta**, analysis of quoted companies undertaken for us by CEPA suggests that the equity beta of gas transmission and distribution network companies is certainly below 1, and is likely to fall at or below the lower end of Ofgem's initial range of 0.65 – 0.95. In addition, market data presented in the CEPA paper suggests a high level of interest in infrastructure assets at the present time.

Notional gearing

8. We see no good reason to depart from the established approach of setting notional gearing at the same level across sectors and companies. Within reasonable ranges, changes in notional gearing are likely to have only a modest impact on the vanilla WACC. This is supported by analysis set out by CEPA in Annex 1.

9. Changes in the asset beta could potentially have a more significant impact on the WACC. However, we would not typically expect network company asset betas to be impacted by changes in the companies' capital structure or by developments such as larger capex programmes or lengthening of cash flows[7]. In theory, asset betas could be impacted by changes in risk allocation between network companies and network users / consumers, but there has been no evidence of this from the market reaction to RIIO (e.g., movements in the share prices of affected companies following key RIIO announcements).

Asset lives and depreciation

10. One of the key conclusions in the RIIO decision document was that economic asset lives should be used to set depreciation allowances, an approach that we fully support. In line with this, Ofgem is proposing to move from the current 20-year asset life for electricity transmission assets to a 45-55 year life. This range appears to be reasonable, although we note that the consultants' analysis undertaken for Ofgem as part of the RIIO process suggested that the technical life of these assets could be 54-60 years, and that there were limited economic grounds to reduce this for depreciation purposes.

11. While we support the thrust of Ofgem's proposals, we are not convinced that transitional arrangements are required for the extension to electricity transmission asset lives. We accept that the proposed change to asset lives is likely to be more significant in overall cash flow terms than the change to repex treatment is for gas distribution, but as previously noted analysis undertaken for us by CEPA indicates that there is considerable investor appetite for infrastructure assets at the present time. Therefore there should be scope for electricity transmission companies to manage the cashflow impacts of changes to asset lives – for example, through seeking new equity injections – without the need for transitional

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[6] We note that the CC looked at both historical and forward-looking approaches to determining the ERP but was relatively dismissive of forward-looking approaches, concluding that a range of 4.0 to 5.0% for the ERP is appropriate. Another relevant reference point is the Bank of England's December 2010 report, which showed a decline in the assumed ERP to 5.0%.

[7] The rationale for this view is that regulated network companies generally have certainty over their revenues from new capex, provided the investment is efficient. We acknowledge however that in some cases network companies may be taking on additional cost risk (eg, costs of over-runs on particular projects) in the course of expanding their capex programmes.

arrangements. This would be more equitable in terms of the balance of cost-sharing between current and future consumers.

12. We also note Ofgem's view that a front-end loaded depreciation profile may be required for gas distribution assets to reflect uncertainty over the role of gas in the transition to a low-carbon energy system. In our view a front-loaded profile is not justified at this stage, and straight line depreciation should be maintained at least for the duration of the next price control period. Further explanation of our rationale for this position in light of uncertainty over the future demand for gas can be found in Appendix 3.

13. The CEPA paper contains a number of worked examples of the financial impact of changes to gearing and depreciation policies, in support of the points set out above.

Pension costs

14. Pension costs are a major component of network charges. At the last electricity distribution price control alone, the networks were allowed to recover over £1billion in deficit funding. Ongoing pension allowance costs represented a further £648million. Our customers pay around 20% of these combined costs.

15. We note that Ofgem's approach to assessing pension allowances under RIIO-GD1 and T1 will follow the principles set out in the June 2010 pensions document. Although we were disappointed that the principle of financial incentivisation was not applied to all categories of pension costs, we still believe that if applied robustly, these principles can deliver significant consumer benefit. We therefore support the general direction of Ofgem's proposals on pensions, but believe there are a number of areas where the proposals can be modified to the benefit of consumers.

16. At a high level, we remain concerned that energy customers are exposed to greater costs and risks than in other regulated industries, particularly in relation to deficit repair. (for example, Ofcom recently reiterated its policy of disallowing BT from passing any of its pension deficit payments onto customers). It is therefore critical that Ofgem's efficiency reviews in relation to pension costs are transparent and robust. In particular they need to reflect a full analysis and consideration of:

    - **economic and efficient benefit levels that are consistent with what commercial operators would provide**. To achieve this, non-network companies in competitive markets must be included in the benchmarking process. This will ensure that consumers pay no more than necessary for network operators to attract and retain good quality staff. It is also important that Ofgem's assessment of pension benefit levels addresses *ex-post* as well as ex-ante inefficiency, including any *ex-post* adjustments that may be appropriate.

    - **efficient management of costs**, both in relation to deficits and ongoing funding. We are actively engaging with the Government Actuarial Department (GAD) review commissioned by Ofgem on this issue, and have stated our view that benchmarking of costs must also be undertaken using wider commercial comparators than just network companies. Moreover, we are of the view that pension cost assumptions (e.g., discount rates) and funding targets for deficit repair should be set at a level that is no more generous than the market median[8]. Indeed, there is a strong argument for setting

[8] We note that the Pensions Regulator considers the appropriateness of a scheme's funding target (and hence the level of its deficit) by comparing the Technical Provisions with the scheme's solvency liabilities and benchmarking this against other organisations. It would be sensible to incorporate this approach into the GAD review.

pension parameters at a margin *below* this level (e.g., 5% below the market median) given the stable, low-risk position and strong employer covenant of network companies.

17. Another important principle is that retained pension surpluses are returned on at least an equivalent basis to consumers who have effectively funded current and previous deficits. Ofgem's policy on this should therefore recognise that in recent price control periods, consumers have effectively been exposed to 100% of deficit repair costs. Consumers should therefore be returned most if not all of any surpluses generated in the near future.

Managing uncertainty

18. The changes to network regulation introduced as a consequence of RIIO mean that networks will now be required to develop business plans for an eight year period, designed around the delivery of a specified set of outputs. We recognise there are a range of issues that affect the delivery of business plans that cannot be predicted with certainty ahead of time, therefore there is a need for a set of tools that can be used by networks to deal with this uncertainty (and ensure they are appropriately financed).

19. While these uncertainty mechanisms improve certainty of revenues for networks, they have a downside of increasing the volatility and uncertainty of network charges. We have significant concerns that the strategy consultation document fails to practically assess the negative impacts of increased network charging uncertainty on consumers and energy markets. Volatility and uncertainty in network charges places a material risk on energy suppliers, which is factored into retail prices in the form of a risk premium on expected levels of network charges. This can represent a tangible barrier to retail market entry, particularly for smaller entrants. The CEPA paper attached in Annex 1 presents some analysis that quantifies the potential level of this risk premium.

20. The consultation document proposes that this volatility is managed by including provisions for reprofiling of revenue collection by the networks, and the use of specific tools (e.g. reopener windows). These are useful "bottom up" measures that networks can use in their business plans. However the document omits to consider the "top down" impact on consumers implied by the aggregation of the uncertainty mechanisms selected by networks in their business plans.

21. There are a number of ways in which "top down" volatility can be mitigated. The simplest way would be to introduce a cap / collar on annual changes in network charges (e.g. set at around 5% per year). Analysis by CEPA has shown that such a mechanism would have a tangible impact on reducing the risk premium suppliers would apply to distribution charges when setting retail prices, and therefore household bills. CEPA also suggest that any financeability impacts of such a mechanism on networks can be addressed relatively simply.

22. To address this gap in the proposals, we ask Ofgem to set up a workstream that addresses the wider market implications of its price control processes, and produce a framework that helps to manage the increased volatility that will otherwise result. We look forward to engaging with Ofgem on this issue in the near future.

Innovation

23. One of the key drivers for RIIO was the need to encourage network companies to innovate and invest for the longer term in order to address the challenges posed by the transition to a low-carbon future. This is a particular issue for electricity networks but there are also important implications for gas, for example in relation to the potential role of biomethane and distributed gas. We therefore welcome Ofgem's proposals to introduce an innovation stimulus fund for both electricity and gas networks under RIIO-GD1 and RIIO-T1, building on the success of the Low Carbon Network (LCN) fund for electricity distribution.

24. We agree with the general direction of Ofgem's proposals for the innovation funds at this stage. The overall size of the funds and the weighting between electricity and gas are reasonable. However, to maximise the benefits of these funds to consumers, a number of design issues will need to be addressed, including:

- **open access** – we welcome Ofgem's position that all licensed energy companies should have full access to innovation funding and be able to take a lead role in consortia bids alongside network companies. Centrica has successfully bid for funding under the LCN together with CE Electric, and we are keen to participate fully in the new funding regimes. Ideally, open access should apply not just to the innovation stimulus package itself but also to the innovation allowance within network companies' revenue allowances.

- **clear and transparent funding criteria** – to minimise administrative burden, the Terms of Reference for the innovation stimulus funds should be as clear as possible. This will ensure that companies do not spend time preparing bids that are unlikely to be considered for funding.

- **additionality and scope of funding** – innovation stimulus funding will only be of benefit to consumers if it facilitates projects that would not have been undertaken otherwise. Therefore, projects that relate to general cost-effectiveness and have direct short-term financial benefits to network companies should be funded from within baseline revenues.

25. Finally, in terms of the technical parameters of the innovation funds within the price control we would favour 'slow' funding given that the benefits are likely to accrue over the long term rather than just the 8-year price control period.

Capex and opex assessment

26. Setting efficient costs for the companies will be a significant challenge under RIIO-GD1 and T1 given the introduction of new output measures and hence the need to focus to a greater extent on companies' forecasts rather than historic costs. The lack of certainty about some of the output measures to be introduced under RIIO makes it difficult to comment in detail on the different technical approaches to cost assessment that Ofgem has put forward in the strategy consultation.

27. However, in general we think there could be a greater role for an iterative process of review and engagement with the companies' business plans than suggested in the proposals. This should also be combined with published independent assessments of the business plans. It is also important that historic cost analysis is not overlooked, particularly in relation to comparative benchmarking of gas distribution costs which was argued to be one of the key benefits of the GDN sales (more detail on this issue can be found in Appendix 3).

28. By combining expert challenge with analysis of historic costs Ofgem will be in a better position to develop the evidence necessary to challenge and engage with the companies during the price review process. This approach will provide top-down sense checks on the forecasts provided by the companies to ensure that they are consistent with maximising value for money to consumers.

Process issues

29. As noted in the overview to this response, we consider that the RIIO model is a positive step forward and can provide the industry with a robust framework within which to meet the challenges of the low-carbon transition. Placing stakeholder engagement (and hence transparency) at the heart of the process of developing and assessing network companies' business plans is vital.

30. Well-justified business plans have the potential to be an excellent tool and represent one of the key 'wins' from RIIO. It is therefore critical that they should be used to engage stakeholders effectively. Engagement on company business plans is important for all of the

networks, but we believe it to be essential in electricity transmission due to the greater complexity of SO/TO interactions and the scale of investment required.

31. With that in mind, we are concerned that an early decision to fast-track one or more network companies could preclude effective engagement on business plans due to the compressed timescales. While we are sympathetic to the principles of proportionate regulation that underlie the fast-tracking regime, it is essential that the benefits of early decisions are balanced against the potential costs to consumers of getting it wrong. Extensive work is still required by the industry to flesh out the current RIIO proposals and develop a comprehensive and robust set of outputs and incentives that can be accurately measured. We therefore think that the additional risks posed by fast-tracking are unlikely to be justified in this first round of price controls.

32. This point is of particular concern given that in most cases key stakeholders do not yet have sufficient information to model or assess the impact of the network companies' proposals on their customers and businesses. The information asymmetry between networks, stakeholders, and Ofgem needs to be addressed by maximising transparency and allowing for effective stakeholder engagement throughout the price control process.

APPENDIX 2 – TRANSMISSION ISSUES

1. In this appendix we address issues which are, for the most part, specific to RIIO-T1. In the sections below, we cover the following topics:

   Electricity Transmission

   - primary outputs versus secondary deliverables;
   - outputs for wider works;
   - timely delivery and interaction between incentives;
   - incentives on TOs to minimise constraints;
   - incentives for timely connections;

   Gas Transmission

   - the need for appropriate output measures;
   - Entry / Exit capacity baselines;
   - interfaces with other gas transmission networks;
   - gas transmission connections; and
   - metering.

2. As a general observation, we believe that the transmission proposals are extremely complex and that there are a number of possible interactions or conflicts within the proposals which it is, at present, difficult to quantify. Examples include interactions between primary and secondary deliverables and the potential inconsistency between incentives on reinforcing local and wider works. This reinforces the concerns expressed previously regarding the risks of the fast-tracking process in terms of compressing the timescales available for effective engagement. Engagement on company business plans is important for all of the networks, but we believe it to be essential in electricity transmission due to the greater complexity of SO/TO interactions and the scale of investment required.

Electricity transmission

3. The biggest challenge facing the electricity transmission networks is to achieve the right levels of investment needed to renew and reinforce the existing networks. It is essential that there is a framework in place to ensure that long-term investment takes place in the network to meet the 2020 targets, support security of supply and reduce constraint costs.

Primary outputs versus secondary deliverables

4. We welcome the importance placed on network investment within RIIO. However, we believe that given the importance of reinforcing the wider network, the sheer scale of the investments and the level of control the TOs have over these investments, network investment should be a primary output rather than a secondary deliverable which feeds in to a number of primary outputs. We believe that this would increase clarity and transparency in this area, as well as allow for greater scrutiny and stakeholder engagement. In addition, it would allow the introduction of secondary deliverables related to wider works, for example, the delivery of the NETS SQSS fundamental review.

Outputs for wider works

5. The RIIO framework outlines two different output options to drive this forward. Our preferred approach would be 'project specific' outputs based on an ENSG-type agreed investment framework. On balance, we prefer this approach on the basis that:

   a) given the level of investment required we believe that this would ensure a more holistic and strategic approach to network investment with greater stakeholder engagement and transparency of criteria used by the TOs and Ofgem to propose and assess network investment;

   b) we do not believe that flexibility should necessarily be compromised given that it does not preclude alterations to projects post sign-off;

   c) it would avoid the application of some of the uncertainty mechanisms that appear to be associated with the more generic 'boundary expansion' approach and reduce the potential for unpredictability / volatility of tariffs which impact on consumers' bills; and

   d) defining a boundary capability, and hence a baseline, can be difficult and often arbitrary. This would be more of an issue with an approach which relies on boundary capability as a baseline.

Timely delivery and interaction between incentives

6. We agree with Ofgem that a mechanism is required to incentivise Transmission Operators (TOs) to deliver projects on time although the detail behind this has yet to be developed. The design of the incentive will need to consider the interactions between SO / TO incentives and the interaction between primary and secondary deliverables, for example incentives on enabling and wider works. In this respect we believe that further consideration is required by Ofgem and further stakeholder engagement would be useful.

Incentives on TOs to minimise constraints

7. We agree with Ofgem that TOs' actions should be incentivised to minimise constraint costs. We believe that the absence of an incentive on Scottish TOs to minimise constraint costs is an issue and that there is a case for passing a proportion of the SO incentive to Scottish TOs, although we note that any mechanism must take into account issues surrounding confidentiality. In England and Wales, we believe that aligning the differing sharing factors between National Grid's controllable SO costs and TO opex costs would provide a better overall framework to manage constraint costs.

Incentives for timely connections

8. At the current time we are uncertain of the benefits of applying an incentive on timely connections for electricity. The codified obligation on TOs to provide a firm offer within 90 days of the application appears fully appropriate and the benefits of potentially incentivising a shorter period are not clear. With regard to the lead up to the actual connection, as Ofgem states, TOs are still in the process implementing new arrangements which are consistent with the Connect & Manage regime and it would make sense to wait until this has been achieved and further experience has been gained.

Gas transmission

The need for appropriate output measures

9. Ofgem's Overview Paper for RIIO-T1 (paras 4.24-4.27) appears to suggest that the definition of appropriate output measures for gas transmission is relatively straightforward. Whilst we would agree that the current "under commitment" arrangements do send an important signal

as to the outputs which network users value, we consider that Ofgem has under-estimated some of the issues involved.

10. A clear signal that enhanced output definitions are required in gas transmission is illustrated by the Fleetwood entry example which arose under the current gas transmission price control. As Ofgem will be aware, a loophole in the user commitment regime has led to a windfall gain to National Grid of some £40m at the expense of users over a five year period. As a result of this anomaly, the baseline capacities at two entry points (Fleetwood and Barrow) have been distorted and no longer give a fair and appropriate indication of the gas transmission outputs required by the market.

11. Following Ofgem's actions to amend National Grid's licence, we will shortly be raising an Income Adjusting Event which should facilitate a remedy to the £40m cost issue, but the distortion to baseline capacities remains. Ofgem should therefore review the appropriateness of current baselines as a measure of outputs and also target National Grid as part of its business plan submission and outputs work to put forward a solution which prevents recurrence of this issue.

Baselines for Entry and Exit capacity

12. The previous discussion also highlights our most fundamental concern with Ofgem's proposed approach. Baselines are at the heart of the current TO price control and NGG's obligations to convey gas. However, current baselines do not reflect the technical capability available on the NTS and it is very difficult to say what consistent measure of output they are intended to represent. We believe that this creates difficulties for the definition of the primary output measures proposed for gas transmission.

13. Especially following the last Transmission Price Control Review, the baselines are now largely commercial data which determine allowed revenue recovery, rather than clear and transparent measures of output. Thus they serve to remove risk from National Grid and can expose system users to inappropriate additional costs when incremental (commercial) capacity is required but physical capacity already exists.

14. Centrica is firmly of the view that the network companies should not be further rewarded for delivery of existing capacity. It is therefore essential to review the current baseline capacity levels against a clearly defined approach to measuring output and ensure that (unlike in the last TPCR) stakeholders are fully consulted and engaged in this process. A more accurate and verifiable measure of technical capacity will result in a more efficient utilisation and development of the NTS.

15. Thus Ofgem should explicitly require National Grid, as part of its stakeholder engagement process, to provide stakeholders with full transparency as to the different measures of entry and exit capacity extant in its business. Further, as part of the business plan and proposed outputs, National Grid must be required to provide evidence that it has engaged with stakeholders in the development of an agreed measure of technical capacity that can be used going forward.

16. Improvements in transparency are required around NTS exit capacity in key locations such as Bacton, for example, including in this case potential transmission constraints and the investment programme that is proposed to address them. Without this, there cannot be the necessary level of informed stakeholder engagement in the RIIO-T process.

Interfaces with other gas transmission networks

17. Consistent with the drive towards a more effective EU gas market and in order to bolster UK gas supply security, NGG should be required to develop suitable output measures around the interface with other transmission systems, including interconnector pipelines such as IUK and BBL. One important element here is the facilitation of access to the widest possible

range of imported gas supplies, within the normal constraints of safety, efficiency and economy.

18. A specific case in point concerns the inability of the National Transmission System (NTS) to accept EU specification gas via IUK and BBL. As part of RIIO, Ofgem should include a clear output measure which would encourage National Grid to develop appropriate solutions such as gas blending (e.g. nitrogen injection) services.

Gas transmission connections

19. Key transmission outputs should include timely and effective mechanisms to ensure connection and to amend or expand existing connections to accommodate the changing pattern of network use. Such amendments might include requirements for changes to connect new (sub) facilities such as storage facilities or LNG import facilities to existing entry points or terminals.

20. The current process is not fit for purpose and not proactively managed by National Grid. The process is not "joined up", with separate requirements to procure system entry or exit capacity via the (applicable) auction or application processes set out in the UNC. The UNC rules for obtaining new or incremental NTS entry or exit capacity need to be carefully correlated with the ability of National Grid to offer connections/reinforcement.

21. As part of the outputs for both customer relations and efficient, co-ordinated future network development, National Grid must have a clear secondary deliverable to develop and maintain a single product/solution that covers both requirements.

Metering

22. There have been a number of recent examples of significant metering errors on the NTS, some of which have gone undiscovered for considerable periods. As a result, they have led to major unanticipated financial impacts on gas shippers and their customers. We are not convinced that NGG systematically follows industry best practice (exemplified by fiscal metering offshore, or at the "beach"), as regards inspection, calibration and verification of accuracy.

23. We would therefore encourage Ofgem to seek from NGG an appropriately enhanced measure of output as regards the standard of metering on its transmission network.

APPENDIX 3 – GAS DISTRIBUTION ISSUES

24. This section of our response provides a more detailed explanation of our views on issues that are specific to the RIIO-GD1 consultation. Specifically, we cover:

- the challenges and uncertainties facing the gas sector and how these should be factored in to the price control review;
- the gas mains replacement (repex) programme;
- operational output measures and incentives related to gas distribution; and
- the capex and opex cost efficiency review for gas distribution.

Challenges and uncertainties facing the gas sector

25. We agree with the key RIIO conclusion that it is appropriate to depreciate network assets over their useful life, rather than over their technical asset lives. However there is still huge uncertainty over the long-term role for gas infrastructure in the transition to a low-carbon energy system. Key determinants of gas infrastructure usage include the success of innovative technologies such as biomethane and Carbon Capture and Storage (CCS).

26. In contrast to this long-term uncertainty, it seems unlikely that usage of the gas network will change radically in the short term. The recent Redpoint Energy report commissioned by the ENA suggests that even in the "low gas" scenarios annual gas demand is relatively stable out to around 2025, and new connections to the distribution network are likely to continue over this period[9].

27. We therefore suggest it would be appropriate to defer any decisions on issues such as front-loaded or accelerated depreciation for new gas distribution assets until the next price control review (assuming this takes effect from 2021). At this stage it is likely to be far clearer how gas network assets will be used over the long term. Introducing significant changes to depreciation policies while there is so much uncertainty over this fundamental issue risks exposing customers to higher network charges, unnecessarily.

28. One alternative approach that could help to address this issue would be to set a shorter price control for RIIO-GD1 than the current proposal of eight years. Setting the price control for a five year period (rather than the eight years as currently proposed) may reduce the need to introduce changes to depreciation policies at this time. A five-year control period could also have additional benefits in terms of managing uncertainty (e.g. possibly allowing the outcome of the HSE review to be incorporated into the next price control without the need for a specific re-opener).

Gas mains replacement expenditure (repex)

29. Repex remains a key issue for Centrica, given that this constitutes the most material category of expenditure under the gas distribution control. Our main concerns are:

- that repex should be focused on areas that deliver most benefit to consumers; and
- that the financial treatment of repex treats current and future consumers fairly[10].

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[9] Average gas demand per household is likely to fall in line with improvements in energy efficiency. However, the Redpoint results, which are based on underlying assumptions derived from the DECC 2050 work, suggest that this effect may be offset by growth in the number of households and new connections to the gas network, leaving overall gas demand broadly unchanged out to 2025.

[10] Our views on the financial treatment of repex, and in particular the case for transitional arrangements, are set out in Annex 1 of this response.

30. We strongly support Ofgem's proposals to introduce a new framework for repex that gives the networks greater incentives to allocate expenditure to those areas that mitigate risk most effectively. Analysis we commissioned from Frontier Economics (presented at the RIIO capex working group on 15 November 2010) questioned whether the current gas mains replacement scheme represents value for money. Specifically, this study concluded that the incremental costs of the accelerated repex programme relative to the counterfactual, outweigh the incremental benefits by £436m. It also highlighted that the majority of benefits of the accelerated scheme are environmental rather than safety related.

31. Based on the conclusion of this report, it would seem likely there will be other opportunities for safety-related spend on the networks that represent significantly better value for money for consumers. We would therefore support Ofgem proposals to replace the current revenue incentive mechanism for iron mains replacement with an incentive that encourages companies to seek the least cost way to reduce risk.

32. It is also important that the design of this new incentive is fully consistent with expectations of future network usage, and that this is reflected in the measurement of risk removed from the gas networks. For example, it would be hard to envisage how investment in new gas mains that are only used for a short period of time could represent value for money.

33. We accept that there are likely to be challenges in developing such an incentive mechanism, for example in relation to accurately measuring risk. We are keen to work together with the network companies and Ofgem to generate solutions to these issues in time for implementation under RIIO-GD1.

Operational output measures and incentives for gas distribution

34. We fully support the movement to an output-based approach to regulation. Over time (and as confidence grows in the output measures selected) we believe that this approach has the potential to deliver significant benefits to consumers. In this section we set out our views on those output measures we consider to be of most importance to Centrica and our customers, specifically:

    - network reliability and LDZ offtake;
    - shrinkage;
    - upstream theft and identification of unregistered sites;
    - the role of xoserve;
    - safety;
    - customer satisfaction; and
    - biomethane and distributed gas;

Network reliability and LDZ offtake

35. As highlighted in the covering letter, the number and volume of offtake measurement errors communicated to shippers has increased exponentially in recent years. Robust, transparent arrangements and incentives are required to ensure that offtake errors are prevented from occurring, identified early, rectified urgently and notified to shippers promptly.

36. While we recognise that not all errors are within the networks' control, recent experience has shown that the largest errors notified have been due to network error[11]. We therefore

[11] In a number of recent cases errors have remained undetected for many months or years, resulting in large, unexpected bills to shippers. Recent examples include Braishfield (1.2 TWh) the Multiple Orifice Plate errors (600 GWh) and Aberdeen (3.2TWh).

support the introduction of an output measure specifically designed to improve performance of the networks in this important area. We would also support the introduction of a specific financial incentive for offtake measurement errors, given the clear need for performance improvement.

37. Due to the relatively large number of small and sometimes insignificant errors that occur, it is essential that any incentive placed upon GDNs for meter error reduction should not be based on the numbers of errors. Instead, it would be more appropriate to concentrate upon metrics such as:

- the actual volume of gas and associated cost;
- the length of time taken to identify and fix the error;
- the length of time taken to provide notification to industry parties; and
- the reason for manifestation of the error.

38. Again, we would be happy to engage with Ofgem and the industry to develop workable incentives along these lines.

Shrinkage

39. We firmly believe that effective incentives can reduce the amount of gas lost from the network and we are therefore supportive of a strong shrinkage regime. There is scope for significant improvement in the current shrinkage regime to better address overall leakage from the network. We do not believe that the use of modelled shrinkage data creates a sufficiently direct incentive on the GDNs. It is therefore imperative that Ofgem moves as quickly as possible to the use of actual shrinkage data in setting the shrinkage incentive as smart meters are rolled out.

40. In the meantime we would expect the GDNs to update the leakage survey used as the basis of their current shrinkage proposals. The survey used to estimate the amount of gas lost in leaks was completed in 2002/03, some nine years ago, and we believe that the age of this research calls in to question its ongoing suitability for calculating shrinkage quantity levels.

41. In addition, we would like to see more transparent reporting of the networks' performance against previous years' shrinkage targets so that we could be reassured that they provided an adequately stretching target. Only by clear reporting of actual performance can industry provide commentary on whether GDNs' shrinkage targets are appropriate

Upstream theft and identification of unregistered sites

42. A key issue related to shrinkage is the accurate identification of unregistered and shipperless sites. While we sympathise with the view that it is the responsibility of shippers and suppliers to reduce theft of gas beyond the meter point, there is still a significant role for the GDNs in identifying many of the causes of unaccounted for gas that occurs before the emergency control valve (ECV). Networks are generally best placed to identify these issues (since they hold relevant data on connections, supply point registers, call outs, gas escapes etc). However, at present there is little financial incentive on them to take a proactive role in this area. We therefore fully support Ofgem's suggestion to require GDNs to develop a Code of Practice in relation to such sites.

43. We also consider that there is a case for introducing a focused financial incentive and / or specific regulatory obligations in this area. One option would be to extend the existing shrinkage incentive to cover all unaccounted for gas, but this may be an overly blunt approach. An alternative would be to introduce a form of "success fee", by which GDNs would receive a payment at the end of each year based on the number of shipperless sites they identify. Data on this should be readily available, and setting an appropriate fee should

be no more challenging than setting an incentive parameter for the wider shrinkage incentive. We would be happy to work with Ofgem and the industry to develop more detailed proposals in this area.

Xoserve

44. We agree with the scope and timing of the proposed review of xoserve. This is particularly important, given the extent of change facing the industry over the duration of the next price control, and the role xoserve will need to play in responding to this change.

45. We agree Ofgem has identified the main topics which need to be addressed – i.e., the facilitation and delivery of industry change, future governance and ownership arrangements, the smart metering programme, Project Nexus and the issue of IGT process centralisation. If alternative governance and ownership models are to be considered, we would advocate something similar to the current Gemserv model which affords suppliers a good level of influence and control.

46. We believe the important issue of establishing a single service provider for all GTs (including IGTs) should also be addressed as part of the xoserve review. While the natural home for any central service sits with xoserve, it has not been within their remit to force a solution to this problem. It is therefore essential that wider and more focussed activity is undertaken to drive through the changes required to existing regulation, including the IGT relative price control, and to force IGTs to migrate their services into a central point.

47. In relation to smart metering, implementation of the Data Comms Company (DCC) will have a significant impact upon the current operational role of xoserve. Over the longer term we expect that the responsibility for providing supply point administration and other activities will transfer to the DCC. Detailed consideration will need to be given in due course to the cutover of arrangements for legacy vs smart meters. However, due to the nature of the activity we still see an enduring role for a standalone gas balancing and settlement body. These activities are fuel specific and do not see a natural linkage of activities across fuels.

48. Project Nexus is essential to ensuring that settlement arrangements reform is delivered and now requires to a clear plan to progress from the user requirements stage to industry design.

Customer satisfaction

49. We support an incentive that focuses on improving the level of customer satisfaction achieved by the networks. However, it is essential that the measures used and targets set for this incentive are sufficiently robust, particularly given the materiality proposed by Ofgem. Ideally, the measure should also adequately reflect the satisfaction of a wider set of stakeholders of the GDNs than solely customers using the emergency telephone line / experiencing interruptions.

50. We would therefore be keen to be involved in the development of this incentive over 2011 (particularly as we already extensively use the favoured measure of customer satisfaction, Net Promoter Scores).

Safety

51. We have already commented on our concerns regarding value for money of the gas mains replacement scheme, and the need to develop alternative measures for incentivising cost-effective reduction in iron mains risk. In addition to this, we believe there is scope to improve the performance of networks in responding more quickly to requests from third parties in relation to non-emergency situations.

52. For example, there may be significant consumer benefit from introducing an output measure focused on network responses to notifications from third parties that assets are not fit for

purpose (although not unsafe). We would be happy to discuss further details in relation to this idea.

Biomethane / distributed gas

53. We support the output measures set out for biomethane. Ofgem's proposal to extend connection standards to biomethane and other distributed gas customers should help to facilitate the speedy roll-out of these projects. We also agree that it is sensible to require GDNs to report the capacity of biomethane connected as a broad measure of environmental impact (although we do not believe it is appropriate to attach specific incentives or penalties to this measure).

54. We agree that the Government's Renewable Heat Incentive (RHI) should be the primary mechanism for providing financial incentives to biomethane (alongside the carbon price signal under the EU Emissions Trading scheme). However there remains significant uncertainty over the level of support provided by the RHI (and therefore expected rollout of biomethane plants).

55. If the level of RHI is at least as attractive to biomethane producers as electricity generation under the Renewables Obligation (RO), then we estimate there could be 40 biomethane projects by 2015 and around 200 projects by 2020. Centrica alone plans to have up to 72 plants operational by 2020 under these assumptions. However the Government's latest proposals fall short of the level of support we believe is necessary to achieve this level of take-up.

56. While we welcome the Government's proposals for the RHI, we also note that there could be a case for further incentives to encourage use of biomethane. For example, we note that in Germany, GDNs are required to provide capacity for distributed gas plant even in cases where this involves installing gas compressors to move gas to a higher pressure part of the grid.

57. Finally, we believe there are a number of practical issues that mean that the costs of the injection related plant is significantly higher than we believe is appropriate at present. In particular, we believe changes to simplify the specification of injection related plant could deliver significant cost reductions (without any adverse impact on consumers).

Capex / opex efficiency review and the benefits of DN sales

58. Overall, we believe Ofgem's suggested approach to efficiency reviews is appropriate. However, we believe it is essential that as well as conducting forward looking efficiency benchmarking, Ofgem draws heavily on past data on network performance.

59. This is particularly important in gas distribution as it is in this upcoming control where Ofgem considered the full benefits of gas DN sales would be realised for consumers. Ofgem's IA in 2004 set out that the benefits of DN comparators would accrue to customers according to a "bell shaped" profile, meaning that most efficiency gains would be delivered in the price control starting in 2013. In 2004, these benefits were estimated to be as high as £225m.

60. We have concerns that if Ofgem's cost assessment under the new RIIO model is almost exclusively "forward looking", then much of these benefits could be overlooked. We therefore urge Ofgem to undertake robust comparative benchmarking of historic costs to complement its forward-looking assessment of GDN business plans, and to quantify wherever possible the specific gains to consumers that have been achieved through the DN sales process.

Uncertainty mechanisms for gas distribution

61. Our general comments on uncertainty are set out in the covering letter and Appendix 1. In terms of the specific mechanisms proposed for gas distribution, we consider that the Traffic

Management Act (TMA) re-opener should be kept to the mid-period review with annual reporting against network business plans to provide transparency to stakeholders regarding performance.