National Grid Transmission

Response to Ofgem RIIO December consultation

Table of Contents

RIIO-T1 Overview paper

Chapter 1	
1	**Do you have any comments on the proposed process and timetable for the review?**
	The application of the RIIO principles are, to date, untested and it will be the practical application of the principles that will be the true test of the process and timetable. It will be a learning experience for all parties involved – including stakeholders and other interested parties as well as the networks. In light of the change in scope of the review from previous price review processes and the shift in onus from Ofgem to the networks to develop the regulatory 'package' we continue to question the requirement for initial business plans to be submitted to Ofgem in July 2011, which is earlier in the review process than previous timetables have required. Taken in conjunction with the increased scope of the submissions and the enormity of the challenges facing the industry, this is a significant increase in the requirements in very tight timescales. We continue to believe that a later submission date would allow networks to carry out more varied and in depth stakeholder discussions to better inform the plans. In parallel, however, we also acknowledge Ofgem's desire to see business plans in July 2011 in order to preserve the opportunity of fast tracking networks through the new processes. On the whole, we remain committed to submitting a well justified business plan in July 2011 and look forward to reviewing it with Ofgem throughout the remainder of 2011 and into 2012. There are a significant number of market and industry consultations progressing in parallel with the RIIO reviews, many of which will interact with the price control outcomes. Over time, some of these will conclude, whilst others remain as ongoing reviews / consultations. Within the categorisation of uncertainty, the interaction of the parallel reviews and market developments should be borne in mind. In order that our plans can reflect stakeholder views, we have undertaken and will continue to undertake a series of stakeholder workshops throughout 2011 and thereafter. In order that best engagement practise can be followed and in light of the uncertainty facing the industry some aspects of our engagement process will not be concluded in advance of submitting the July 2011 well justified plans. It is therefore anticipated that there may be some evolution in our assumptions or plans as a result of evolving stakeholder preferences. The fact that our plans will continue to evolve as stakeholder requirements mature and some aspects of uncertainty become clearer sits uncomfortably with the proposal to use the first business plan as the basis of the IQI incentive. We provide some further views on this elsewhere in this response. Ofgem has included draft licence conditions as an element within the scope of a well-justified plan but has not provided clarity in terms of requirements. It would appear more effective to introduce draft licence conditions further on into the process once new or amended mechanisms have reached mutual agreement.
Chapter 2	
1	**Do respondents consider there are any interactions with other policy areas that have not been highlighted in this chapter?**

	One area of uncertainty is the rapidly evolving and area of climate change thinking, as demonstrated by the Committee on Climate Change's 4th carbon budget. This is an area of significant change which will continue to progress over the price review and price control period. In addition, there will be policy areas which are debated through stakeholder engagement, which will interact with some of the existing principles and may impact on more than one network's proposals if effected.
2	**Do respondents consider that the transmission and gas distribution price control periods should remain aligned for future review periods?**
	In light of the volume of work involved in a price review process, it would appear to be sensible to stagger the burden on stakeholders, Ofgem and networks alike by staggering the review periods in order that the price review processes are not aligned going forward.
Chapter 3	
1	**Do you have any comments of the overall approach to stakeholder engagement?**
	We strongly welcome the principles of stakeholder engagement and have embraced these principles in our comprehensive approach. We will continue with a range of activities to 2013 and beyond and look forward to further joint working with our stakeholders to continue the development of a network which is fit for the future. Accordingly, the feedback we receive will inform our business plan. We note Ofgem's continued focus for networks to engage proactively with consumers. This is a difficult area for Transmission due to the relatively small contribution to consumer bills (currently 3-4%). We will continue to engage proactively with consumers and representative groups on the issues such as visual amenity which are important to them. Stakeholders have welcomed our approach and their opportunity to shape what they see as the future of energy. The development of the 'Talking Networks' brand for our stakeholder activities has been embraced as this has facilitated our aim to reduce the use of business acronyms, make our sessions and supporting material open, transparent and easier to understand. We have dedicated web pages to present all of the feedback we have received. To date, stakeholder groups have expressed concern about the tight timescales for engagement as there are many areas for discussion, and other organisations that are competing with us for their time. As a result we view stakeholder engagement as an ongoing activity which will continue to inform our current and future business plans and the stakeholder contribution will naturally evolve over time.
2	**Do you have any views on how our engagement process and that of the network companies could be made more effective?**
	Due to the demands on individuals' and organisations' time, a more joined up approach would be welcomed by stakeholders. We have tried to facilitate this, but have been unsuccessful to date. We will continue to propose joint working where appropriate in order to manage the stakeholder burden. The Ofgem output workshops and working groups which took place over autumn and early winter 2010 had a wide remit and covered a large amount of content. The wide range of issues that were discussed, coupled with the time restrictions, meant

	that National Grid attendees felt that each RIIO output couldn't be allocated the optimal time for open debate, capturing all ideas and conclusions to be reached in accordance with the December 2010 strategy document deadline. Had more time been available, ideas could have been further explored and work could have commenced on other important areas such as uncertainty mechanisms and incentives.
Chapter 4	
1	**Do you consider the proposed outputs and associated incentives, along with the other elements of the proposals, will ensure companies deliver value-for-money for consumers and play their role in delivering a sustainable energy sector?**
	Whilst the proposed outputs and associated uncertainty mechanisms together with other elements of the price control have the potential to ensure that companies deliver value-for-money for consumers and play their role in delivering a sustainable energy sector, it is not possible to be definitive until further detail has emerged, in particular due to the lack of development of proposed incentives.
2	**Do you consider that the proposed outputs and incentive arrangements are proportionate (e.g. too many or too few)?**
	The number of proposed outputs for RIIO-T1 appears to be proportionate given the central role that transmission has to play in the sustainability, affordability and security of the energy industry. It is not possible to say whether the associated incentive arrangements are proportionate until further detail regarding the scale of these incentives has emerged.
3	**Do you have any views on the proposed outputs or incentive mechanisms?**
	We have been fully involved in the working groups organised by Ofgem to develop the outputs. Whilst we broadly agree with the proposals, we note that the development of the outputs and incentives framework is currently lagging behind Ofgem's original plan. This is not surprising given the scale of the task and the associated limited timescales, together with the parallel activity of a TPCR4 roll-over submission. Given the importance of the change to the RIIO framework and the critical part that the identification of outputs plays in this, it would be better to take additional time ahead of the submission of the first well justified business plan to ensure that the outputs and associated incentives are fully developed and supported with adequate analysis from network companies and stakeholders. Overall, it is difficult to be definitive about the proposals until this next level of detail has been developed.
Chapter 5	
1	**Is our proposed approach to cost assessment appropriate?**
	At a high level we agree with the principles of the cost assessment process and welcome the RIIO model which places more focus on companies' forecasts rather than a mechanistic process. This is a positive evolution to facilitate the approach required by industry given the challenges ahead. We recognise it will be beneficial to both networks and Ofgem for an increased

range of regulatory tools to be available compared to previous reviews, and the range outlined seems sensible and allows for broad assessment. We do hold reservations around the nature and application of some of the cost assessment tools outlined; possibly because more information is required to explain how they are going to be utilised. The detail of how the principles are applied will be key in a number of areas.

More specifically:

- It is not clear from the documents (without practical experience) how the focus will principally be placed on company forecasts, as opposed to using the range of tools mechanistically. There is a risk that the assessment falls back into approaches used in previous price controls, and becomes more mechanistic than is intended. Focus will be required during the review period to ensure the overarching principles are maintained.

- The seven criteria for choosing analytical techniques outlined in section two seem sensible and are good objectives, but some of the new tools outlined are at risk of contradicting elements of the criteria. For example, the robustness of totex benchmarking using FERC data is reliant on using comparable, consistent and normalised data to draw meaningful conclusions between FERC and the relevant networks. This is not possible due to insufficient information in the FERC data to normalise it to allow comparison – an issue acknowledged by Ofgem's own recognition that surrogate data may need to be used. Lessons should be learnt from Ofgem and National Grid's experience of development of the E3Grid benchmarking study which suffers from a lack of transparency and robustness due to the immaturity of the process. We recognise that totex benchmarking should be part of the regulatory toolset (and is a better guide than total cost or just using opex or capex benchmarking), but this should not be heavily relied upon in assessing efficient costs unless consistency and normalisation of data can be achieved. This is especially the case where it is not possible to split distribution activities from transmission activities in third party data. Such mixing of data sets can materially skew any benchmarking as shown by work we have undertaken in assessing publicly available data in this area.

- Whilst we agree with the intention to benchmark future costs, it is not clear how this will be possible in practice. The limited forecast data sets available in this area making such analysis difficult. For example FERC data (referred to as one of the main benchmarking data sets) is historical only and there are fundamental issues in attempting to normalise this data for use in benchmarking. There is little other information available due to competition law requirements. As noted by Ofgem there are different scales of Electricity TOs, so limiting future benchmarking to these comparatives will not necessarily work either. Historical benchmarking may have to be used as a proxy to give Ofgem enough information to assess costs. In this case results of mature benchmarking studies such as the International Transmission Operation and Maintenance Study (ITOMS) and the Gas Transmission Benchmarking Initiative (GTBI) should take precedence over any new studies which have not been tested. Our responses to the totex benchmarking questions below give more detail on these studies.

- It is not clear how Ofgem will bring together the bottom-up and top down approaches. We agree that it will be beneficial to assess costs using both approaches but it will be necessary to explore areas where inconsistencies exist, rather than 'cherry picking' apparently efficient answers from different elements of analysis, creating an unachievable whole.

	• A number of assessment tools suggest that reviewing historical indices or data will give all the information required in order to assess future costs. For example in the area of Real Price Effects only historical indices will be used to assess future price pressures. Using only historical data would downplay fundamental uncertainties in networks' plans to 2021 and beyond. Assessment needs to include consideration of future pressures including changes to supply and demand in the market. • We have reservations in relation to assessing closely associated opex via an overhead uplift to direct opex. There are some significant areas of focus for RIIO-T1 (such as facilitation of system access and responding to planning / consents requirements) which fall under the definition of closely associated opex. At present the strategy document suggests these areas will not be specifically reviewed, and instead funded by an uplift to direct opex. The relationship between direct and closely associated opex is unlikely to be linear for any company, let alone cross Network. It is unclear from the documents how this will be adjusted for to ensure that necessary expenditure in these areas are sufficiently funded in RIIO-T1. • Benchmarking of business support costs across Networks also gives us concern. The cost drivers currently stated for use in this assessment (such as customer numbers) are very Distribution centric so will need refreshing to cover Transmission cost drivers. At the very least a cross Network driver should be used otherwise costs will not be normalised cross Network and therefore the benchmarking is not robust. In addition to this there is no explanation as to why the business support costs per cost driver will be the same across Transmission and Distribution. For example why should the costs of IS per network length be comparable between Distribution entities and Transmission entities when the work they are performing can be considerably different?
2	**Do you have any views on our proposed process for proportionate treatment?**
	We have concerns over the timescales driven by the fast-track process, as previously discussed. We acknowledge Ofgem's ambition to accelerate the early stages of the RIIO-T1 process, but maintain that this gives limited time to: • Incorporate any new requirements which are to be outlined in the March 2011 document • Complete detailed stakeholder engagement • Develop an appropriate package to meet future challenges of uncertainty Whilst committed to delivering the initial RIIO-T1 submission in July 2011, we remain of the view that the quality of this deliverable will be compromised by the time constraints under which is has to be developed. Therefore, we will be looking to continue to progress any outstanding issues in preparation for the updated submission in 2012.
3	**Do you have any views on the criteria for assessing business plans? Are any of the criteria highlighted inappropriate? Should any additional criteria be added?**
	The criteria seem appropriate and we do not suggest any additional criteria to be added. More detail on our views on the criteria, and specifically the assessment of past performance which will influence the assessment of the regulatory approach for

	each company, is included in response to the 'Business plans, innovation and efficiency incentives' consultation.
4	**Do you have any views on the proposed role for competition in third party delivery?**
	Please see the answers to questions 1 and 2 in chapter 4 of the "Consultation on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives" consultation document for detailed response on this question. In summary, two things are required to serve the interests of consumers when network investment is required: • Identify a good design (giving the customer the required benefits for expected costs) • Deliver selected design efficiently (to achieve the design at lowest life time cost) The extent to which it is in consumers' interest to separate delivery from design (and separate these from operation) will depend on circumstances. The benefits of enabling new entrants to deliver and own transmission assets that are identified in the consultation document may easily be unwound if a suboptimal design is selected (delivering the wrong thing efficiently does not help consumers). Indeed, given the importance in today's planning process of addressing the interplay between design choices and the expected delivered outcomes, especially on environmental and amenity aspects, the ability to progress any solution to benefit consumers may depend crucially on this interface. There are a number of issues which would need consideration should this option be pursued, including: • The benefits from a centralised approach to network design, development and integration • The ability to chose between mutually exclusive options • Exploitation of our experience and knowledge of delivery factors to incorporate into the design of any potential solution Through the delivery models we already employ for significant infrastructure projects, we believe we are delivering optimum value for money.
Chapter 6	
1	**Do you have any views on the uncertainty mechanisms identified?**
	The uncertainty mechanisms described for Transmission are similar to those that we currently have as part of TPCR4. Broadly, these mechanisms have performed well and therefore we agree with the proposals to retain them. The major area of change is electricity revenue drivers. The proposed changes in this area, which have been primarily driven by changes to the transmission access regime, are helpful. We broadly agree with the changes to the generation connection uncertainty mechanism and we welcome the proposals for wider transmission works. We would welcome the opportunity to develop these proposals further with Ofgem and other stakeholders and also to explore potential incentive options.
2	**Are there any additional uncertainty mechanisms required that we have not**

	identified?
	The document mentions a number of additional uncertainty mechanisms that have been raised by the network companies, but only provides a view on potential uncertainty mechanisms for RPI and legislative change. We are particularly interested to further explore a potential uncertainty mechanism for RPE, but it would be useful to further develop each of the areas identified in the document. Whilst we can do this as part of the development of our well justified business plan, there may also be advantages to the development of consistent mechanisms across all transmission networks. The document describes uncertainties for which there will be sufficient information to calibrate a volume driver ex ante and those for which this will not be possible and specific re-openers will need to be used. This is a helpful distinction, although it should be noted that during an 8-year price control, other unforeseen requirements may emerge and we would welcome a discussion on the appropriate treatment with Ofgem and our stakeholders. In addition to the above, uncertainty mechanisms to deal with gas network flexibility and asset replacement investments are also likely to be required. The outputs and incentives document describes the need for outputs and secondary deliverables which would adjust our obligations with respect to network flexibility and asset replacement, and it is important that this is coupled with uncertainty mechanisms to adjust our revenues accordingly.
3	**Are there any mechanisms that we have included that are not necessary and, if so, why?**
	As described above, the mechanisms described are similar to those we currently have under TPCR4, and broadly these mechanisms have performed well and therefore we agree with the proposals to retain them.
Chapter 7	
1	**Do you have any views on the role of innovation in RIIO-T1?**
	Innovation should be core to both mechanisms and we are very encouraged to see Ofgem include an innovation allowance within the business plan and the creation of an innovation stimulus fund. We have previously outlined our detailed thoughts on innovation in our response to the open letter consultation on innovation (letter dated November 23rd, 2010).
2	**Do you have any views on the time limited innovation stimulus?**
	This is a welcome step forward in pursuing innovation to meet the challenges of sustainable networks and the vision of a low carbon future. We have previously outlined our detailed thoughts on the fund in the letter referenced above.
Chapter 8	
1	**Do you consider that the proposed package of financial measures identified will enable required network expenditure to be effectively financed?**
	In considering whether the proposed package of financial measures will enable network expenditure to be financed, this response covers

- Equity finance
- Debt finance
- Notional gearing
- The financeability assessment

The response concludes with a selection of quotations taken from recent analyst coverage of National Grid. These quotes illustrate many of the points raised in both this and subsequent answers within this consultation response.

Equity Finance

There is a presumption within the RIIO framework that equity finance will be available, when needed, at the allowed rate of return. Ofgem's proposed approach is to use CAPM, sense checked to other approaches. We agree that CAPM has a role to play in the estimation of the cost of equity but would be concerned if too much reliance was placed on CAPM. The concerns are detailed in our response to Question 5, Chapter 8 below and include the empirical data available and need to consider cash flow duration and risk.

There is a risk that a theoretically acceptable package fails to attract finance from investors. The UK energy networks are not just competing for funds with other UK infrastructure industries, they are competing for funds globally. It is essential therefore that the returns, cash flows and dividends available to equity are seen as attractive to current and future investors if the investments that are needed to meet the requirements of users of the networks are to be financeable.

Our response to Question 5, Chapter 8 also demonstrates that the economic principles of supply and demand can be used to demonstrate that if there is a requirement to inject equity, the returns to equity need to increase. That same response also shows that if the market reacts negatively to information, the required equity return will increase further.

In this respect, both the proposed changes in economic asset lives and increase in capitalisation of repex change the well understood regulatory contract. Our concerns with regard to these proposals, both in principle and regarding the details of the asset lives proposed are detailed in our response to Questions 2 and 3, Chapter 8 below. We note recent consultations by both DECC and BIS recognise the importance to investors of predictability and regulatory commitment and there can be little doubt that the current proposed package of measures will increase regulatory risk in the minds of investors as demonstrated by the quotations from recent analyst coverage included at the bottom of the response to this question.

Ofgem has previously acknowledged in the RPI-X@20 review the importance of regulatory commitment yet the proposals for asset lives and repex reverse previous regulatory decisions. The justifications for the current regulatory treatments are no less appropriate than they were when they were introduced. The willingness of Ofgem simply to change its approach in this way is a clear demonstration of regulatory risk and investors will require additional return to compensate for this risk.

Not only does the change in asset lives and repex capitalisation increase regulatory risk but it also defers cash flows. As Oxera explain "*There remain strong grounds to believe that an increase in the duration of cash flows for regulated energy networks will lead to a material increase in the cost of capital. An indicative estimate of the magnitude of one of the components of the duration effect is 60 bp"*[1]. A more detailed consideration of this issue is included within our response to Question 2,

[1] "What is the cost of equity for RIIO-T1 and RIIO –GD1?", Oxera report prepared for the Energy Networks Association, February 2011

Chapter 3 of the Financial Issues section. Intuitively there can be little doubt that an increase in the duration of cash flows causes an increase in the required return, not least because it exposes investors to increased stranding and regulatory risks.

Based on the points above it is clear that a number of factors would require an increase in equity returns if the networks are to be financeable. However, whether or not Ofgem's range for the cost of equity will be acceptable depends on the package of risk and reward. It is clear that the RIIO proposals introduce additional risks to investors in networks, such as:

- Exposure to cost variances for 8 years rather than 5
- Stronger financial exposure to output performance
- Increased regulatory and stranding risk through deferring a higher proportion of cash flows to future regulatory periods

However, as yet insufficient detail on the proposed package of incentives is available to calibrate the risk reward package. We would therefore encourage Ofgem to provide more information on the nature and strength of incentives to allow such an assessment to take place.

Ofgem's own calibration of the DPCR5 package included RORE analysis. We are greatly concerned that the process adopted seemed to result in the allowed return being artificially reduced because the package of incentives could theoretically have allowed an efficient network to earn a return that Ofgem considered too high. If Ofgem intend to use CAPM, informed by other approaches, to set the allowed return, then that allowed return should not subsequently be reduced if networks are expected on average to earn additional returns through incentives which, by nature, are likely to be weighted towards diversifiable risks for investors. While we agree that there should be a floor on the return that equity could receive, incentives should be designed to reward companies for efficiently delivering the outputs that stakeholders want. Provided the incentives function appropriately and do not encourage inappropriate behaviour, higher returns will be a reflection of better than expected outcomes for consumers and there should be no cap on delivering what consumers want.

Debt Finance

Our concerns regarding the proposals for a cost of debt index are detailed in our response to Question 4, Chapter 8 below. Not only do we believe the cost of debt indexation approach could fail to finance efficient debt costs in principle but, in practice, the index proposals systematically fail to finance significant efficient costs associated with debt finance, namely the costs of debt issuance, new issue premia, bank facility fees, commitment fees, credit rating agency fees, and the costs of carrying cash etc.

Further, the index uses an investment grade (A) that is higher than the vast majority of the networks covered by the RIIO-T1 and RIIO-GD1 controls, fails to consider bonds with a tenor over 10 years despite the average tenor being 18.6 years, and fails to fund the costs of the inflation risk premium.

It is our view therefore that the current package of financial measures systematically fails to finance efficient debt costs. To the extent that the index does not adequately cover efficient debt costs, the returns received by equity holders will be further reduced.

Notional gearing

We welcome the work that Ofgem has shared so far on setting the appropriate notional gearing level. We would welcome further clarity on this important subject and look forward to developing this further in the coming weeks. We believe that notional gearing should be set with reference to the cash flow risks faced by the company and a need to ensure the networks are financeable.

Given the importance of notional gearing, we are concerned that the current level of gearing has been misunderstood. There are numerous references within the Financial issues annex to networks having gearing higher than was assumed in the notional capital structures for the current price controls. For example, paragraph 3.14 of the Financial Issues annex refers to network gearing of around 70% while noting the Scottish transmission companies have lower gearing. The paragraph notes that networks have achieved a "comfortable investment grade" despite the level of gearing being higher than assumed in allowances. We believe this conclusion is based on an inappropriate measure of gearing.

Our net debt to RAV gearing is quoted in the audited Regulatory accounts of NGET and NGG in 2010 as 56% and 57% respectively, i.e. below the rates assumed in the notional capital structure for both TPCR4 and GDPCR1. Further, data taken from the December 2009 PwC report for Ofgem as part of DPCR5 (see our response to question 3.4 below) shows gearing for the electricity distribution companies was on average 43%, i.e. much lower than 70%. Unfortunately, we believe Europe Economics[2], and by extension Ofgem, have therefore based much of their analysis and conclusions on an inappropriate gross debt to RAV rather than net debt to RAV definition of gearing.

Credit and equity metrics

With regard to the financeability assessment, our detailed views are included in our response to Questions 1 and 2, Chapter 4 of the Financial Issues annex.

With regard to equity metrics, we believe the current proposal to review Notional RAV/EBITDA and Regulated Equity/Regulated Earnings needs to be augmented by a dividend yield measure, such as Notional Dividends/Notional Equity, and a dividend cover ratio. We note that Ofwat considered dividend cover to be a key ratio in their December 2009 Final Proposals and the importance of dividends is clear from the analyst comments below. If Ofgem acknowledge the importance of dividends to investors we believe it would be helpful to clearly emphasise this in the March document.

It is important to recognise that financial ratios are just one of the factors that the rating agencies take into account in assessing credit ratings. Other factors, especially the stability of the regulatory environment and ownership model are equally important. It is therefore extremely important that Ofgem take care not to jeopardise the current positive view of the UK regulatory framework through the changes that the RIIO model will bring, and should avoid breaking with established precedents.

In assessing credit ratings, the rating agencies typically have a particular focus on the values of credit metrics over relatively short timescales which might typically be 3 to 5 years. As a result the credit metrics need to have values that are consistent with the targeted credit rating in the short term as well as in the medium and/or long term. Longer-term considerations (both qualitative factors and the values of financial ratios) do matter[3] but, as Ofgem have previously recognised[4], it is not sufficient for

[2] "The Weighted Average Cost of Capital for Ofgem's Future Price Control, Final Phase 1 report", Europe Economics, December 2010, paragraphs 4.25 and 4.27

[3] If rating agencies were to have concerns regarding the reliability of the future regulatory framework, this would affect credit ratings today

[4] "Gas Distribution Price Control Review Fourth Consultation document", Ofgem, March 2007, Appendix 10 Paragraph 1.3

Ofgem to focus on the medium and long term only as this will not ensure financeability.

Equally, with regard to the credit rating metrics themselves, Ofgem has identified the key metrics as net debt / RAV and PMICR, with some consideration also being given to FFO interest cover and RCF/net debt. Whilst PMICR and net debt/RAV may be used by some agencies, they are not used in isolation and neither are they used uniformly by all of the agencies. In commenting on PMICR during GDPCR, Ofgem noted, "*The agencies make it clear that this is only one ratio, and that they rate companies based on a range of financial ratios, having regard to compliance with short-term target levels as well as medium-term trends, a review of financial strategy, and other qualitative judgments including business risk assessment*."[5] For an assessment of financeability to have any value and relevance, Ofgem must continue to reflect the approach of all the agencies and look at a wider range of ratios. Given that different companies and debt issues are rated by different agencies, it is important to consider the approach of all the main ratings agencies and the metrics they use.

In accordance with Ofgem's financing duty and to provide the necessary comfort on headroom to the rating agencies, the price control must allow a reasonably efficient licensee with the assumed notional gearing / capital structure to maintain a comfortable investment grade credit rating under plausible scenarios. Thus, Ofgem's assessment of the key credit ratios needs to be carried out for the assumed notional capital structure under different scenarios, and not just for a base case. Given the practical difficulties associated with doing this, it would be more appropriate for the metrics to be targeted at a rating level of "A-" rather than "BBB", consistent with the approach adopted by Ofwat at PR09[6].

Analyst reactions to December consultation document

The quotations below are taken from analyst coverage since the publication of the consultation document. We believe they are particularly relevant to the question of whether the current RIIO proposals will be attractive to investors.

- *"There may be debate about whether [Ofgem's return range] is sufficient to reflect the risks associated with a longer control period and changes to asset lives."*
- *"Ofgem still plans to extend depreciation lives in the name of technical correctness, reversing its previous adjustments to accommodate the sector's investment profile. These changes are theoretically NPV neutral, but will have implication for cash flows, and we are not convinced they are either necessary or justified."*
- *"We believe it is important to distinguish between theory and the real world. Ofgem needs to work hard during the review process to give the comfort necessary to maintain investor appetite in the sector."*

  Source: Bank of America Merrill Lynch - Fraser McLaren - December 2010

- *"We are already concerned that this process will lead to a settlement that is unattractive to equity investors. The UK requires enormous investment in its*

[5] "Gas Distribution Price Control Review Fourth Consultation Document", Ofgem, March 2007, Appendix 10 paragraph 1.3

[6] Ofwat's Final Determination on Future water and sewerage charges 2010-15, Section 1, Key Messages: "*We have targeted financial ratios that are consistent with an A-/A3 credit rating. The majority of companies are in this position. Where one particular indicator (and in a small number of cases, two indicators) for a single rating agency may not meet the required threshold, we ensure that it meets the criteria for a strong BBB+/Baa1 credit rating*."

	energy network infrastructure and the positive sentiment coming from government and Ofgem does not necessarily match up with some of the detail in these documents." Source: RBS - Iain Turner - January 2011 • *"[The latest Ofgem proposals] pose substantial risks to cashflow and earnings and could therefore put the capital structure and the sustainability of the dividend at risk."* • *"It is still in early days...but in our view, these proposals raise [NG's] regulatory risk profile."* • *"Even taking a generous interpretation suggests that these proposals could potentially reduce the long term earnings and cash flow generation by a meaningful amount – c20% from 2013 onwards. Obviously a reduction in earnings makes the current dividend level, and the current balance sheet structure look a good deal less certain. For example it would probably reduce dividend cover to only around 1x."* • *"It now appears clear to us that if NG's capex remains close to current projected levels (around £5bn p.a.), there could be the requirement to strengthen the balance sheet with disposals – although this is not straightforward, and may need a revisit of the dividend – or further equity issuance. The Ofgem proposals would only exacerbate this."* Source: Morgan Stanley - Bobby Chada - January 2011 • *"Equity investors may well not accept the "jam tomorrow" investment proposition.. [And] we believe that this could lead to such stocks underperforming significantly."* *Source: Unicredit - Scott Phillips - January 2011* • *"At a presentation on 1 February, Ofgem set out more of its thinking. The regulator is keen to try to assure investors that (1) it is taking a measured, balanced approach, (2) that it will ensure that companies can finance their functions, and (3) that it is seeking to attract, not deter, investment.* *We have no doubt that this is Ofgem's intention, but its proposals contain some serious changes that we feel do not fit with the aims stated above – some appear to be change for changes sake… We also doubt that Ofgem really appreciates all of the concerns from a listed equity market perspective."* Morgan Stanley - Bobby Chada - February 2011
2	**Do you have any views on our proposed approach to depreciation?**
	This response highlights our concerns with the current proposals for asset lives and the proposal to capitalise 100% of repex in the RAV, as well as commenting on the proposed depreciation profile. **Principle of moving to economic asset lives** The RAV asset lives chosen in previous price controls were selected on the basis of a number of considerations. Recurring themes include the impact on the financial position of the companies and the impact on longer term prices. These considerations were considered important for the consumer as well as the companies. By way of example, when commenting on the advantages of the tilting depreciation approach adopted for the RECs during DPCR3 Ofgem stated "*it is a means of increasing certainty with respect to the financial position of the distribution*

	businesses and the path of prices in the longer term. The benefits of this will be felt by both customers and companies."[7] As recently as January 2010, in their RPI-X@20 consultation[8], Ofgem listed a range of factors that should be considered is setting asset lives and the approach to depreciation. These included: • Transparency and predictability • Balancing the interests of current and future consumers • Price signals (and cost reflectivity) - how important is it that consumers and users face appropriate price signals • Incentives (i.e. impact on incentives faced by the networks) • Reliance on cash flow ratios (and whether this is necessary and appropriate) There is a long history of Ofgem considering a range of issues such as these. These issues are equally relevant today and it is not clear why Ofgem now believe it is appropriate to determine RAV asset lives with a sole focus on economic asset lives. Ofgem's decision to adopt an economic asset life appears to be based on the objective of balancing the interests of current and future consumers. National Grid and others have previously questioned whether or not a <u>retrospectively applied change</u> in asset lives would improve intergenerational fairness at all in electricity. As figure 2.10 of the Financial Issues annex demonstrates, an increase in asset lives increases the long term costs that future consumers pay to the benefit of customers in the short term. It is difficult to reconcile the short term subsidy that would be provided to current consumers at the expense of future consumers with Ofgem's objective to balance the needs of current and future consumers more fairly. Current consumers continue to benefit from artificially low charges caused by the discount between net replacement cost and RAV incorporated into the initial RAV valuation of pre-privatisation assets. This discount has been retained for the advantage of both current and future customers by the maintenance of the current level of depreciation. The impact of an increase in lives would be to utilise the whole of this discount to artificially depress current charges and further distort economic prices which could have unforeseen consequences. It appears to be widely accepted that energy costs will rise in the future given the increased demands for declining fossil fuel resources and the need to decarbonise the economy, with the resultant impact on electricity generation costs. Current customers are benefiting from relatively cheap energy and minimal restrictions on emissions which will not be available to future customers. This is an intergenerational energy issue that would be exacerbated by any extension of asset lives. Investors are asking 'why do asset lives need to be extended?' and it is clear that Ofgem has not adequately demonstrated or communicated this need. The extension of asset lives is a key concern to investors that is undermining their confidence to invest in the sector. Ofgem must demonstrate how their proposals help to solve intergenerational energy price inequality and make this analysis available for critique before implementing any changes. Without this supporting evidence, regulatory risk, in this case the perceived risk of the regulator making unwelcome and unnecessary changes to the regime, will be significantly increased

[7] DPCR3 Final Proposals (1999), paragraph 5.35
[8] "Regulating Energy Networks for the Future: RPI-X@20 Emerging Thinking – Embedding Financeability in a New Framework", Ofgem, January 2010, paragraphs 4.6 to 4.22

causing an increase in the return required to attract equity.

Replacement Expenditure (repex)

The Final Proposals in September 2001 for the Transco 2002 Price Control included the following words in the summary *"The renewal programme is primarily concerned with present safety requirements rather than increasing the network's capacity or functionality for the benefit of future consumers, suggesting these costs should be expensed and met within the price control period. Nevertheless there will be some advantages to consumers in the future as replacement spending will be lower and newer assets tend to require less repair and maintenance. To deal with these tensions, ensure that Transco is able to finance its activities and ensure that price reductions are sustainable beyond the next price control period, 50 per cent of replacement spending over the next price control period will be expensed in the year that it is incurred and 50 per cent will be treated as capital and added to the regulatory asset base*." Paragraph 6.8 of the same document stated that financeability was a key consideration in deciding the proportions to be expensed and capitalised and 6.9 stated that capitalising 100% "*would put significant strain on Transco's key financial ratios and jeopardise its ability to retain an investment grade credit rating*."

The issue was then reviewed in the first Gas Distribution price Control Review in 2007, and Ofgem confirmed that they considered the 50/50 split to be appropriate[9].

It is interesting that Ofgem acknowledged that the primary purpose of the repex programme is present safety requirements for current consumers. All of these points above remain valid today and we see no justification for placing a greater proportion of the cost burden on future consumers.

Technical Lives

The technical life analysis is based on the life of installed assets. This ignores the significant changes in the assets planned to be installed or changes in the usage of assets. In many cases assets are being replaced by higher technology equipment that has a shorter asset life. Also, assets such as circuit breakers that have traditionally been used for faults only are now being used to manage the system such that National Grid has now introduced a new category of high duty circuit breakers which have a shorter asset life.

Contrary to the comments in the Financial Issues annex paragraph 2.11, we believe this expenditure will be material as we progress through the price control period.

Economic Lives

We have significant concerns with the choice of economic lives. With regard to the lives chosen we believe there are shortcomings that have been adopted in the analysis undertaken by CEPA which have not been corrected in Ofgem's proposals.

An analysis is provided in figure 2.4 of the Financial Issues annex of the uncertainties that have been considered. Numerous other factors could also be relevant such as increasing legislative health and safety requirements for example, or an increase in the number of shorter life generation assets connected to the network. A significant change in the mix of generation assets is expected in the next couple of decades, including the introduction of more plant with potentially shorter lives such as wind farms. While the network assets connecting them will typically have technical lives consistent with other assets, they are unlikely to have the same economic life because the connected asset will have a shorter life. This economic

[9] "Gas Distribution Price Control Review Final Proposals", Ofgem, December 2007, paragraph 9.30; and "Gas Distribution Price Control Review Updated Proposals", Ofgem, September 2007, paragraphs 9.44 to 9.46.

factor has been completely overlooked in the results presented such that future consumers are likely to find themselves paying for the connection assets of one or two generations of plant that has long since ceased to provide economic benefit.

The asset life decision needs to consider the impact of depreciation charges on consumer bills and the risk of asset stranding, which, itself, would contribute to an increase in the required rate of return and higher consumer bills.

We note that CEPA believe that under the 'Green Transition' scenario gas peak demand could fall to 70% of today's level, but annual demand would drop to 30%. Within these figures it is generally accepted that there will be greater resilience in demand for gas transmission than distribution in the future, provided cost effective CCS technology can be developed, so the impact on gas distribution will be even more pronounced. The price paid by consumers (in terms of Transmission and Distribution cost per unit) will be a function of average demand, not the peak requirement during a period of time and so the asset life decision should be informed by annual demand projections. The asset life and depreciation choices need to ensure that, after considering the cost of future investments, the depreciation charges recovered in the future are sufficiently low that they can be covered by the smaller consumer base. If the future costs of the network are too high, gas may become uneconomic, accelerating the decline of gas utilisation.

The Project Discovery scenarios reviewed by CEPA ran to 2025. CEPA have extrapolated them to 2050 for the purposes of their analysis. The Redpoint 'Gas Future Scenarios Project – Final Report', published in October 2010, also considered four scenarios out to 2050. In the 'Electrical Revolution' scenario, the use of gas for both transmission and distribution is significantly reduced over a 30 to 40 year period with the transmission and distribution networks fully decommissioned by 2050. In this context, a 45 year asset life is too high. Indeed, in that scenario, average gas demand is less than 20% of the current levels as early as 2040.

For gas assets, the decision to retain 45 years as the asset life is based on a flawed argument. As highlighted in paragraph 2.26 of the Financial Issues annex "*There is significant uncertainty around the future use of the gas network with annual load and future peak demand likely to be no higher than currently. In some scenarios, gas usage could be much lower. The future of the gas network depends upon the successful development of a number of technologies including CCS and high use of bio-methane*." The annex then goes on to conclude that "*Our view is that it would be premature to reduce asset lives given that there are scenarios, where gas will remain an important element of the energy market*".

As already mentioned, if average demand is falling, the network costs to be recovered will need to fall. If this does not happen assets will be stranded. If there are credible scenarios where gas demand will be significantly lower the asset lives should be reduced to prevent such stranding. The logical argument should be that faced with uncertainty lives should be reduced not, as appears to be the case in the proposals, to postpone a decision to reduce asset lives until there is certainty that the assets will not be required. The approach currently adopted postpones the decision to reduce asset lives until it is too late, significantly increasing stranding risk.

Depreciation profile

Given the uncertainty faced by the gas industry we agree that some form of front loading depreciation for gas distribution assets is appropriate. Front loading already applies to the assets installed as of 2002. We do not agree that the assets installed post 2002 but before RIIO-GD1 should continue to be depreciated on a straight line basis. Such an approach would result in the proportion of capex recovered through depreciation charges on 2012/13 investments being lower than that for 2013/14

	investments. Applying a front loading depreciation profile to all assets would make more sense economically as well as being simpler and more transparent. For this reason we would recommend the application of a front loaded depreciation profile for all gas distribution assets. The future of gas transmission is also uncertain and, as acknowledged by Ofgem, is conditional on the development of CCS technology. Consequently, we believe it may be more appropriate to adopt a front loaded profile in transmission as well. Adopting a front loaded depreciation profile is an additional and effective way of mitigating stranding risks but to the extent that investors perceive the risks of stranding to increase, the allowed return will have to be increased. We agree that back loading the depreciation charge for electricity would not be appropriate. Forecast increases in demand will require further investment which will have to be paid for by future consumers. We therefore agree with the proposal to retain straight line depreciation for electricity.
3	**Do you have any views on our proposed approach to implement any transition arrangements over one price control period where possible?**
	Notwithstanding our concerns with the proposed changes to the asset lives and the proposed change to repex treatment in gas distribution, Ofgem's commitment to introducing appropriate transitional arrangements where moving to the use of economic asset lives in a single step would cause excessive disruption to financial markets or raise concerns over financeability is welcome. We believe transitional arrangements should also seek to achieve regulatory consistency and avoid complexity. We also welcome the acknowledgment in paragraph 4.8 of the Financial Issues annex that transitional arrangements should extend over more than one price control period where needed to allow a network to maintain financeability. **Financeability and disruption to financial markets** Paragraph 2.45 acknowledges that transitional arrangements can provide time for businesses to re-organise their financing arrangements as "*immediate equity injections are not practical*". Faced with a forecast of deteriorating financial ratios, rating agencies will require that potential future deterioration to be addressed immediately. Consequently, if an objective of transitional arrangements is to avoid an impractical short term requirement to raise equity as a consequence of a change in asset lives, those arrangements need to ensure credit ratings are maintained over both the short and medium term. **Regulatory consistency** We note with interest that the current consultation from The Department for Business Innovation and Skills (BIS) on the 'Principles for Economic Regulation' includes predictability within its principles for economic regulation and states: • *"the framework of economic regulation should provide a stable and objective environment enabling all those affected to anticipate the context for future decisions and to make long term investment decisions with confidence"* • *"the framework of economic regulation should not unreasonably unravel past decisions, and should allow efficient and necessary investments to receive a reasonable return, subject to the normal risks inherent in markets"* In our opinion, the current proposals for electricity asset lives and repex treatment unreasonably unravel past decisions. Investors have legitimate expectations at the time they make their investment and Ofgem continues to acknowledge the importance of regulatory commitment.

	Changes to the asset lives and the treatment of repex such as those proposed by Ofgem contradict these legitimate expectations causing investors to price in additional regulatory risk, for which a higher return is required. Ofgem has suggested that the changes outlined in their RIIO proposals have been signalled for some time. A number of publications during January, following the consultation, demonstrate that this signalling was not as clear as Ofgem might have hoped. The additional detail in the December consultation document, on asset lives and cost of capital in particular, has triggered further analysis on the potential impact of the changes and the results of this analysis have caused some concern. **Simplicity** Transitional arrangements should be simple so that they can be easily understood by all stakeholders. Applying new electricity lives to new assets only achieves this objective. Making step changes in asset lives during a price control is not a simple option. For example setting a life of 30 years from 2013/14, 40 years from 2017/18, and 45 years from 2021/22 means that expenditure incurred during TPCR4 will change life several times. Not only is it difficult to explain to investors why expenditure which they funded on the basis of a 20 year life suddenly changes to 30, then 40, then 45, but getting the calculations correct is relatively complex to model. Each change in life requires a comparison of the written down value using the two lives, with the book value difference depreciated over a smoothing period which would also have to be determined. Simply dividing the cost by the new life would not give the correct depreciation charge over the lifetime of the asset. **Proposed Approach** Taking in to account the considerations highlighted above we believe applying new electricity asset lives to new assets only would help to minimise the increase in regulatory risk caused by the change in the basis on which investors have provided finance. Further support for this argument is provided by the position taken by DECC in their recent consultation on electricity market reform which explains the merits of ‘grandfathering’ current investments. It is perhaps a moot point as to whether applying a new asset life to new investment only is a transitional measure or not. After all, any increase in the proportion of repex capitalised in the RAV will only be applied for new expenditure, if at all. Nevertheless, while we note Ofgem’s preference to limit transition arrangements to one price control period, the length of the transition has to be such that companies are financeable. In this context we do not believe an artificial time constraint of one price control should be imposed. Paragraph 4.8 of the Financial Issues annex recognises that such a constraint may not be realistic. Most importantly of all, National Grid would encourage Ofgem not to limit any options in its March document. Ofgem has not yet received the companies’ business plans, nor have they done their own financial modelling. CEPA’s modelling was very high level and we have doubts about whether it adequately considered the intricacies of the regulatory regime such as the requirement to model tax cash flows etc, and the use of a nominal interest rate in those calculations. For these reasons we would encourage Ofgem to leave their options open until the receipt of company business plans. Indeed Ofgem may wish to add further transition options such as a re-profiling of income, and / or variations in the proportion of totex capitalised.
4	**Do you have any views on our preferred approach to remunerating the cost of debt?**
	Principle

We acknowledge that the proposed approach to setting the cost of debt uses similar information to that considered by Ofgem in recent price controls but, in principle, the move to setting the cost of debt based on a mechanical index of past values may not be appropriate in all circumstances. Previous price controls have recognised the value of taking different evidence and ways of estimating the cost of debt into account, and this more flexible approach should be retained. This issue is illustrated quite nicely by figure 3.3 of the Financial Issues annex which gives an example where the actual cost of debt exceeds the allowance for every year of the price control.

Ofgem has previously stated that the proposed cost of debt index will reduce risk for companies because a network will know that even if an efficiently raised bond costs more than the index at the date it is issued (due to rising interest rates) they can be confident that the costs will be recovered eventually (due to the 10 year trailing average). However, figure 3.5 of the Financial Issues annex demonstrates that the average tenor of bonds is 18.6 years so the index would only include that bond for just over half of its tenor. Further, in paragraphs 3.18 and 3.19 of that annex Ofgem appear to contradict their own arguments that debt costs will be financed by the index. In responding to network arguments that structuring a debt profile to more closely match the index to reduce risk would be costly and inefficient Ofgem avoid the question and simply say it is for networks to choose how they finance themselves.

Practical Issues

In terms of practical implementation details, with the exception of being “fully mechanistic”, as explained above, we agree with the criteria used to evaluate options. We also agree that the requirement in paragraph 3.24 of the Financial Issues annex for the index to “accurately reflect the cost of debt for an efficient company” carries a high weight. However we have concerns regarding:

- The choice of indices
- The tenor of debt
- The omission of a significant tranche of efficient debt finance costs
- The period of the trailing average, and
- The failure to fund the inflation risk premium

<u>Choice of index and tenor of debt</u>

We would make the following points on the proposal to use an average of Bloomberg 10 year BBB and 10 year A corporate bonds:

- We agree with the use of GBP corporate bonds as this will preserve efficiency incentives far more effectively than utility bonds.
- We do not agree that the index should be an average of A and BBB bonds. Contrary to the comments in paragraph 3.29 that *“licensees are roughly equally divided between a broad A rating (covering A+/A/A-) and a broad B rating”* analysis shows that the vast majority of energy networks are rated between A- and BBB. Further, changes in the duration of cash flows are likely to put further pressure on credit ratings. We would therefore propose an average of the A- and BBB indices.
- We do not agree with the use of 10 year bonds. The networks invest in long life assets and often raise debt with a longer tenor than 10 years. Figure 3.5 showed the average tenor is 18.6 years so an index of 10 year bonds is not representative of the costs efficiently incurred by the networks. While Ofgem state that the difference between 10 year bonds and longer dated issues is

not material, as a matter of principle, we believe it would be more appropriate to move to the iBoxx 10+ index which would include longer dated issues.

Omission of efficient costs of debt finance

A key objective of the index is to reflect the efficient costs of debt finance. As currently defined the index fails in principle to fund the full efficient costs of debt finance and should be amended to make allowance for such costs. These include (but are not limited to):

- Debt issuance fees
- New issue premia
- Bank facility fees
- Credit rating agency fees
- Commitment fees
- The costs of carrying cash

These costs are typically reported as finance costs in accounts and so are not covered by operating cost allowances. In the case of debt issuance fees Ofgem has suggested in paragraph 3.37 of the Financial issues annex that these costs do not need to be considered because companies have historically managed to raise debt at rates lower than the proposed index and the outperformance should fund such costs. This position cannot be justified, not least because such outperformance cannot be relied upon to continue.

Several aspects of the RIIO proposals can be expected to put considerable pressure on credit ratios, and the debt premia that energy utilities have to pay, relative to the corporate market. These include:

- An increase in the duration of cash flows due to changes in asset lives and repex capitalisation.
- Increased use of incentives which may increase the volatility of cash flows
- Exposure to cost variances for eight years rather than five

In this context, it is clear that any past outperformance cannot be relied upon in the future to fund the efficient costs of debt finance currently ignored by the index.

Further, it is difficult to reconcile Ofgem's position on debt issuance costs with that adopted for equity, where a specific allowance is provided to cover the costs of issuing equity.

An appropriate way to account for these costs would be to add a pre defined number of basis points to the cost of debt index. Our response to Question 6, Chapter 3 of the Financial Issues annex demonstrates that this is the approach that Ofwat have explicitly, and Ofgem implicitly, adopted in the past.

Trailing average

With regard to the trailing average:

- We agree that a simple average rather than a weighted average is preferable on the grounds of simplicity and transparency.
- On the 10 year length of the trailing average, if debt has an average tenor of 18.6 years it would seem to make sense to have a longer trailing average.

Inflation risk premium

Finally, we have concerns that the index does not adequately capture the risks

	associated with inflation nor fund the costs of mitigating them. The index uses nominal bond yields to derive a debt premium which is then added to a real risk free rate. Although this works in principle for debt which is issued as RPI linked, network companies typically have to raise fixed or floating rate nominal debt because the market for corporate RPI linked debt is not sufficiently developed. This mismatch can lead to the real cost of debt actually incurred for nominal rate debt being higher than the allowed real cost of debt. The reason for this is because the implied inflation rate from the proposed approach may be overstated due to the demand for index linked gilts as an effective hedge against inflation risks. According to recent research by the Bank of England, this inflation risk premium has been estimated for the UK to have been approximately 30 basis points for investments with a five year maturity[10]. This means the proposed approach for setting the allowed real cost of debt would be approximately 30 basis points lower than that actually incurred for debt raised with nominal rate coupons.
5	**Do you have any views on our proposed approach to assessing the cost of equity and the associated range of 4.0-7.2 per cent?**
	Paragraph 3.2 of the Financial Issues annex describes 4 key principles for the approach to setting the cost of capital under RIIO: • use of a real WACC-based approach; • use of a long-term trailing average for the cost of debt, where this is updated annually; • use of CAPM, sense-checked to other approaches, for setting the cost of equity; • a "principles-based" approach to the calculation of notional gearing, where the size of the equity wedge reflects the company's risk exposure. **WACC based approach** We agree that it is appropriate to set allowed return on a real WACC basis, and see the benefit in terms of regulatory risk that this approach brings by maintaining consistency with past price controls. However, the inter-generational consequences and impact on financeability of this approach, which defers the RPI element of returns by indexing the RAV, need to be considered in setting other elements of the control, including the approach to asset lives, depreciation and capitalisation. **Cost of debt** We have reservations regarding the proposed cost of debt index, as explained in our response to Question 4, Chapter 8 above. **Use of CAPM** For investors to have confidence in the regulatory framework requires an approach that is consistent with past price controls to be adopted. Thus we agree that CAPM, sense checked by other approaches, has a role to play in the estimation of the cost of equity. Our responses to Questions 7 and 8, Chapter 3 of the Financial issues annex includes comments on the proposed range for the equity beta and resulting cost of equity. However, we have concerns with any approach that relies too heavily on CAPM. These are:

[10] Joyce, M., Lidholdt, P. and Sorensen, S. (2009) 'Extracting inflation expectations and inflation risk premia from the term structure: a joint model of the UK nominal and real yield curves', Bank of England working paper 360.

- The empirical data available
- Uncertainty as to what represents ‘normal’ financial conditions
- The need to consider cash flow risk
- The need to ensure returns are attractive to investors

Data availability

With regard to the availability of data we have two concerns, namely the limited number of data points, and difficulties in using historic data to set future equity returns.

- Since the privatisation of the energy networks there has been a progressive reduction in the number that are publicly listed. Even those that are publicly listed are typically not pure-play single network companies. This creates concern as to whether the data reviewed is sufficiently representative to be used to set equity returns.
- CAPM relies on the use of observable historic data to determine required future equity returns. The new RIIO framework of regulation fundamentally changes the risk profile of the energy networks. Significant changes to the length of the price control, the nature and strength of incentives and uncertainty mechanisms, and changes in the duration of cash flows to name but a few mean that historic CAPM data cannot reliably be used to determine the cost of equity in the future.

‘Normal’ financial conditions

An underlying assumption of the proposed CAPM approach is that an appropriate cost of capital for an 8 year RIIO price control that will not even start for another two years can be set using historical information, with a particular focus on the relatively recent past (i.e. the past decade).

The past decade initially saw a period of relative stability, combined with freely available credit and a generally declining risk free rate (as implied from index-linked gilt yields - see Europe Economics report Figure 3.2). This was followed by a period of almost unprecedented financial instability (particularly in 2008 and 2009), accompanied by reduced credit availability, higher risk-free rates, higher debt spreads, and significant instability in equity markets. The financial conditions in the preceding years are now seen as a precursor of the financial crisis, suggesting that neither of these periods can be seen as "normal". Whilst it would be understandable if regulators were reluctant to base an estimated future cost of equity on the conditions at the height of the financial crisis, it would be equally inappropriate to assume that the current conditions, or indeed those in the years leading up to 2008, will again be seen during the period from 2013 to 2021. Further support for this proposition comes from McKinsey's December 2010 report "Farewell to cheap capital? The implications of long term shifts in global investment and saving", which analyses the reasons for low and declining capital costs over the past 3 decades, and concludes that the conditions that led to cheap capital (not just in the UK but globally) may be expected to reverse and lead to a higher cost of capital in the next two decades.

While we do know that the last decade was not ‘normal’ we do not know what the new ‘normal’ will be. Faced with such uncertainty, great care needs to be taken in setting an assumed cost of equity (within the allowed WACC). It is not only inappropriate to place weight on current spot values of the risk free rate and equity risk premium, but a 5 year trailing average (as shown in Figure 3.11 of the Financial Issues annex) or even 10 year trailing average cannot be considered a sound basis on which to estimate future values. In such conditions, the cost of equity should be based on long term average values of the risk free rate (2.5%[11]) and equity risk premium, using values that are consistent with the directly observed long-run total market equity return which is generally recognised to lie in the range from 6.5% to 7.5%[12], although a value of 8% was more recently suggested as the long-run value of total market equity return in DPCR5[13].

Cash flow risk

As a theoretical model, CAPM considers the covariance of a company's share price with the market. It is based on the principle of providing a return to compensate for non diversifiable risks. CAPM can be used to set the allowed equity return provided the cash flows of the business have been risk adjusted, i.e. that the future cash flow projections have been adjusted to consider the risks associated with those cash flows. In the past, regulators have found it very difficult to risk adjust future cash flows and so have tended to reflect these risks in the allowed equity return. Consequently, CAPM needs to be supplemented with a consideration of the cash flow risks the networks face.

With regard to cash flow risk it is important to recognise that the impact of the proposals cannot be fully understood at this stage as the nature and strength of incentive mechanisms and scale of uncertainty mechanisms is currently unknown.

Nevertheless, as highlighted below, there are a number of ways in which the RIIO proposals can be seen to be increasing the cash flow risk the networks face. It is important to bear in mind that these risks are often asymmetric and are not adequately remunerated through the CAPM framework. Given the inherent difficulties in risk adjusting the future cash flows of the networks, such risk needs to be compensated for through an increase in the allowed return.

Our response to Question 2, Chapter 3 of the Financial Issues annex covers cash flow risks in more detail. It specifically covers:

- Regulatory risk
- Increases in the duration of cash flows
- Proposed changes to the nature of the price control package, such as 8 year controls and an increased focus on output delivery

Returns attractive to investors

There is a presumption within the RIIO framework that equity finance will be available when needed at the allowed rate of return. There is a risk that a theoretically acceptable package fails to attract finance from investors. It is essential therefore that the returns, cash flows and dividends available to equity are seen as

[11] "Report on the Cost of Capital provided to Ofgem", Smithers & Co. Ltd., 1 September 2006, page 4 (1st bullet point). Note also that the PwC report "Office of Gas and Electricity Markets - Advice on the cost of capital analysis for DPCR5 Final Report", 1 December 2009, Summary and Conclusions final sentence, suggests that 2.5% is "consistent with the mid-point level for the real RFR that has generally been used in regulatory determinations since 2000."
[12] "A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K.", Smithers & Co Ltd, 13 February 2003, page 49; and "Report on the Cost of Capital provided to Ofgem", Smithers & Co. Ltd., 1 September 2006, page 4 (1st bullet point).
[13] "Office of Gas and Electricity Markets - Advice on the cost of capital analysis for DPCR5 Final Report", PwC, 1 December 2009, Summary and Conclusions: page 2 gives Risk Free Rate between 2% and 2.5, where 2.5% is the long-run rate, i.e. "*consistent with the mid-point level for the real RFR that has generally been used in regulatory determinations since 2000*", and then on page 3 for EMRP "*Taking a longer-term approach, we consider that a range of 4.5% to 5.5% is appropriate. The upper end of this range is broadly consistent with long-term evidence on the actual excess returns on equities in the UK*." Thus, a long-term view of total market return would be 2.5% + 5.5% = 8%, at the top end of the PwC range from 6.5% to 8%.

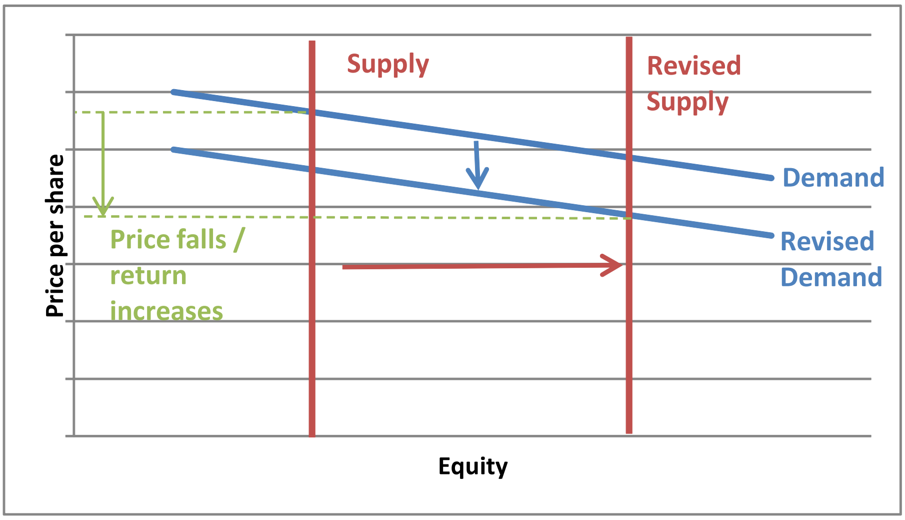
attractive to current <u>and future investors</u> if the investments that are needed to meet the requirements of users of the networks are to be financeable.

The economic principles of supply and demand can be used to demonstrate that if there is a requirement to inject equity, the returns to equity need to increase. While the market for listed equity is liquid, it cannot be described as perfect given the existence of transaction costs and lack of perfect information (as illustrated by the impact announcements or investor notices can have on share prices). In the absence of a perfect market, the demand curve is downward sloping. In this context, an investor will only demand more shares in a company if the price falls, i.e. their expected returns on the investment increase.

In the absence of any information signals, an increase in equity will move the supply curve to the right causing the equilibrium share price to drop, i.e. required returns to rise.

However, equity issues also send information signals to the market. That information may result in a downward movement in the demand curve causing an even greater reduction in price and increase in required returns. In the context of a regulated network, the best case scenario is perhaps that the equity is required to fund future capex. If such investment attracts the same return as the current RAV, investors may be concerned about increased construction risk or a dilution of returns with existing incentive performance spread over a larger equity base.

However, the RIIO proposals for asset lives and repex treatment extend the duration of cash flows. Investors will see deterioration in the cash flows of the business, and in the dividends they receive. The best case is that some investors will consider the impact to be NPV neutral, but for others the short term deterioration in dividends and cash flow will be seen negatively, pushing the demand curve down and further increasing the return required to attract new equity. The graph below illustrates these impacts.



In practical terms, the equity markets do not sit on large amounts of cash looking for a home. In order to fund additional equity investments in energy networks this cash will have to be moved from other competing investments. The yields and returns available on those competing investments will have to be considered by Ofgem when determining an appropriate allowed return on equity.

Notional gearing

We agree with the use of a “principles-based” approach to the calculation of notional

	gearing, where the size of the equity wedge reflects the company's risk exposure. We believe the notional gearing must also be set such that the notional company will have acceptable credit and equity metrics under plausible scenarios, across the full range of timeframes, and we believe that this consideration is most likely to determine the notional capital structure. **Conclusion** To summarise, CAPM has a role to play in estimating the cost of equity. However, the RIIO proposals increase the cash flow risks the networks are exposed to, risks which CAPM does not adequately address. There is therefore a need to consider this cash flow risk in the range set for the cost of equity. More fundamentally though, we are entering an era where the challenge is no longer just about the return current investors require on their investment but is increasingly about allowing a return that will attract new investors and sources of finance. In the absence of further information on the strength of incentives and uncertainty mechanisms it is not possible to be definitive on the required cost of equity at this stage. However, one thing that is clear is that with increasing cash flow risk and a need to set an allowed return that will be attractive to investors, the cost of equity that is allowed will need to be at least at the top end of the range proposed by Ofgem.
6	**Do you have any views on other elements of our financial proposals?**
	The questions above cover: • Financeability • Asset lives, repex and depreciation profile • Transition arrangements • The proposed cost of debt index, and • The cost of equity In our response to this question we make additional points in relation to: • The tax trigger • The proposal to calculate gas entry and exit incentives using a vanilla return • Other technical tax issues • Pensions • RAV methodology **Tax trigger** The purpose of the tax trigger dead band is to avoid immaterial changes in charges caused by changes in the factors detailed in paragraph 1.4 of appendix 3 to the Financial Issues annex. For changes within the dead band, licensees are exposed to small variations in tax costs, whether they are positive or negative. As currently proposed, if the tax trigger is activated the adjustment only covers the difference in tax costs excluding the dead band, and the adjustment to revenues in many cases is delayed, potentially for three years or more[14].

[14] A change in tax costs in 2014/15 will be included in a tax return submitted by March 2016. HMRC agreement to the return and Ofgem review during 2016/17 would then allow for charges to be adjusted in time for the 2017/18 formula year. Any delay in securing HMRC or Ofgem agreement would further delay recovery in revenues.

Ordinarily this may be a symmetric arrangement but for the gas distribution networks, the move to IFRS reporting will result in a material increase in tax costs, probably for all years from 2014/15. Under such circumstances the dead band of the tax trigger would be an asymmetric downside only risk which would have to be reflected in the allowed rate of return. Further, given the materiality of the sums involved, the delay in recovery could well put the financeability of distribution networks at risk. For this reason, we would suggest that the impact of moving to IFRS should be adjusted in the base revenues by re-running the financial model as soon as the expected impact and timing are confirmed, rather than being the subject of unnecessary delay.

In any event, we would propose that the dead band should be used only as a threshold to determine whether an adjustment to revenues is required. In the event that a change in tax costs goes beyond the dead band, revenues should be adjusted in full for the change in tax costs.

There is also an interesting interplay between the tax trigger and the proposed cost of debt index. The cost of debt allowance impacts on revenues in two primary ways, through the return on the RAV, and through the tax allowance due to the tax shield on debt. On the assumption that the annual adjustment to revenues for the cost of debt index includes modelling the tax allowances it would be logical to include all changes in tax legislation in that modelling. Under these circumstances it would make sense to always use the tax legislation that will be in force for the relevant year, in which case legislative changes in corporation tax and capital allowance rates etc would no longer need to be included within the scope of the tax trigger.

Tax Incentives

Paragraph 5.13 of the financial issues annex proposes to move to calculating incentive schemes such as gas entry and exit on a vanilla WACC basis with the calculation of an incentive specific tax allowance.

As outlined in the response to Question 1, Chapter 8, to make retrospective changes to the regulatory regime increases regulatory risk which would need to be compensated for through the allowed return. Both DEC and BIS have issued consultations highlighting the need to avoid such retrospective changes to ensure investor confidence. For this reason, any move to change the tax treatment of incentives should only be considered for implementation on a prospective basis only. Consequently, those incentives that were triggered during TPCR3 and any triggered during TPCR4 should continue to operate on the current pre-tax basis.

From a pure tax treatment perspective only, the proposal to calculate incentives using the vanilla WACC could be appropriate for new incentives with effect from the new RIIO controls. However, we believe such a change would introduce unnecessary complexity to incentive arrangements which are already very complex. Increasing complexity runs counter to Ofgem's desires to increase transparency and simplify the licence. Calculating an incremental tax allowance for the incentive scheme would prove extremely complex.

The incentive mechanisms under consideration, e.g. gas entry and exit, are complex schemes to begin with. They typically incentivise National Grid to find the most efficient way to deliver additional capacity obligations. Those capacity obligations could be provided through a discrete capital investment project, through commercial arrangements, more complex investments (such as a combination of discrete projects and deep reinforcement), or any combination of these. The incentives are deliberately designed not to dictate to the licensee what that efficient solution is. In this context it is impractical to model the incremental tax effects in advance as the level and nature of any expenditure will not be known. An alternative would be identify the tax impact on an ex post basis but there could still be issues with identifying all of the relevant expenditure concerned and an ex post incentive scheme would reduce the efficiency incentive on the licensee.

Even if the issues above of identifying the relevant expenditure could be addressed, assumptions would have to be made on the funding of any capital expenditure. At the margin all investment is financed by debt but for larger schemes a notional equity wedge may be appropriate, in which case the costs of raising equity need to be factored in. For material investments, there may also be a need to consider the financeability of the licensee.

In some circumstances the incremental tax allowance could be negative. However, a negative tax allowance can only be recovered if the licensee is paying tax elsewhere. This would require a consideration of the incremental incentive scheme tax flow alongside all of the other modelled tax charges. As a simplification, this issue could be addressed by ignoring negative tax numbers.

The introduction of the tax trigger creates further complications. If a specific tax allowance is being calculated, that allowance should be included within the scope of the tax trigger. Consequently, all relevant incentive schemes should be included within any assessment of whether the tax trigger is activated, and incentive revenues would need to be adjusted in the event that a change in tax legislation etc does activate the trigger.

The issues above would need to be addressed, and records kept (separate tax pool allocations for each capital scheme, separate tax computations, separate funding, cash flow and debt calculations) for each and every occasion a gas entry or exit incentive was triggered. These incentives tend to flow through to revenues over multiple price control periods so the records requiring to be kept could grow to unmanageable levels.

As a result of the complexities highlighted above, We would suggest that a pragmatic approach would be to continue to operate such incentive schemes on a pre-tax basis.

Other technical tax issues

The proposed cost of debt index will result in an annual recalculation of allowed revenues. As explained above, one of the ways in which the cost of debt allowance impacts on revenues is through the tax allowance due to the tax shield on debt. The modelling of interest costs includes an assumption for RPI inflation. Given the importance of that assumption to the modelled tax allowance we believe there should be an agreed pre defined mechanism for selecting the appropriate RPI inflation assumption to be used. This assumption could then be updated each time the allowed revenues are recalculated. This mechanism should be included in a future consultation.

In paragraph 1.5 of appendix 2 of the Financial Issues annex, Ofgem explains the treatment of tax losses that was adopted in the GDPCR, namely that tax losses are logged and subsequently deducted when the timing differences that led to the losses reverse. The same paragraph does not consider this to be an issue for transmission. However, with the scale of capital investment required in the energy networks in the next decade there is the potential for tax losses to be incurred. In such an event, we would expect the same treatment of logging up of tax losses to apply. Our comments above consider the possibility of tax losses for individual incentive scheme calculations.

Paragraph 1.24 of appendix 2 refers to computing ex post pension adjustments net of tax. We agree that licensees should not be given the tax allowance twice but, equally, the adjustment needs to ensure that the correct post tax adjustment is made as revenues received by the company will be taxed.

Paragraph 1.26 of the tax appendix refers to the manner in which the interest payable (and receivable) will be calculated in the financial model. Previous financial models have simply multiplied debt by a nominal interest rate. It can be proven that this calculation systematically overstates the interest cost leading to an understatement of the tax allowances. This understatement causes the returns to equity to be lower than notionally allowed. To calculate the interest payable correctly, the calculation should take a form similar to that used to calculate the return payable on the RAV, i.e. by discounting it at the relevant rate.

The tax claw back mechanism for excess gearing may need to be modified slightly if Ofgem implement the proposals for a cost of debt index. The principal of the mechanism is that excess tax benefits will be clawed back if gearing exceeds the notional rate and interest costs exceed those modelled at the price control. Under the proposed cost of debt index there is an expectation that there will be periods when actual cost exceed the allowance. It is therefore possible that a minor increase in gearing above the notional capital structure could trigger a significant claw back of tax benefit caused by the company concerned suffering higher debt costs than allowed by the cost of debt index. We believe a tolerance should be introduced to the mechanism to guard against this risk.

Pensions

With regard to pension costs, Ofgem has referred in the past to the strength of its commitment to fund regulated pension costs. We believe this commitment is weakened by the proposal to fund pension deficits based on updated valuations at as 31 March 2011 or 30 September 2012. Licensee funding commitments will be based on the latest triennial valuation, not an interim date that has no bearing on the costs the licensees will actually incur. Given the proposal, which we agree with, to update the valuations after each triennial valuation, we believe it would be in the interests of consumers to align the date used to set revenues with the latest formal valuation.

With regard to ex post true up adjustments for pension payments we believe there is no credible alternative other than to use the WACC. The TPCR4 deficit allowances were set using the WACC. Also DPCR5, which also set out decisions that would apply to other networks[15], stated that companies would be kept revenue neutral on a net present value basis if actual payments differed from the notional 15 year recovery period. Revenue neutrality was defined in DPCR5 as '*the company will be paid back the cost of financing the gap*'.[16]

We believe the current proposal to assess PPF costs as part of benchmarked total costs is flawed. PPF and administration costs relate to the scheme as a whole and the networks reviewed by Ofgem have schemes of varying maturity. In the case of the NGUK scheme, active members constitute only 5% of the total membership so to load each active member with the costs of 19 inactive members for benchmarking purposes is clearly inappropriate.

Finally, changes in the way that PPF costs are levied are still open to consultation. At this time there is considerable uncertainty with regard to the level of costs that will

[15] "Electricity Distribution Price Control Review Final Proposals – Allowed Revenues and Financial Issues", Ofgem, December 2009, Chapter 5 Summary explained that, although focusing particularly on how they apply to the DNOs, the document set out Ofgem's decisions following their consultation on the pension principles which provide a consistent and common framework across all the network businesses that Ofgem regulate.

[16] "Electricity Distribution Price Control Review Final Proposals – Allowed Revenues and Financial Issues", Ofgem, December 2009, paragraph 5.8

be incurred, though there is a clear expectation that for schemes which currently pay a very low levy due to a strong D&B failure score, those cost will more than double. In the event that there remains considerable uncertainty at the time of Final Proposals we believe an appropriate ex post adjustment or pass-through mechanism should be put in place to protect both consumers and licensees alike from uncontrollable risks.

RAV methodology

We recognise that the move to equalise the incentive rate by adopting a totex approach brings a number of practical benefits. By including business support and non operational capex costs it will avoid unnecessary boundary issues between what is and is not totex. It will also help with a consideration of the capex / opex interactions in operations and network development but if the assessment of efficient operating costs and capital expenditure is still done independently at the next review, overall efficiency is still not being assessed. Ofgem mention the possibility of totex benchmarking but, in practice, this is much easier said than done.

Finally, the definition of totex in paragraph 1.3 of appendix 6 of the Financial Issues annex states that all costs relating to excluded services activities are excluded. This is not correct. National Grid Electricity Transmission's conducts a number of excluded services activities for which costs are not separately identifiable. Consequently, regulated revenues are calculated by including all relevant costs and then the projected excluded services revenues are deducted. Consequently, for some licensees, totex will include excluded services activities.

Tools for cost assessment

Chapter 2	
1	**Have we proposed an optimum range of techniques** **(a) Are there better techniques that we have not included?** **(b) Are we applying the appropriate techniques in the appropriate areas?**
	We broadly agree with the principles of the proposed cost assessment process. We recognise it will be beneficial for both networks and Ofgem for an increased range of regulatory tools to be available compared to previous reviews and the range outlined seems sensible and allows for broad assessment. We are currently unable to suggest any better techniques, however we will retain reservations around the nature and application of some of the cost assessment tools outlined until more information is available on how the techniques are to be used in practice. More specifically: • It is not clear from the documents (without practical experience) how the focus will principally be placed on company forecasts, as opposed to using the range of tools mechanistically. There is a risk that the assessment falls back into approaches used in previous price controls, and becomes more mechanistic than is intended. Focus will be required during the review period to ensure the overarching principles are maintained. • The seven criteria for choosing analytical techniques outlined in section two seem sensible and are good objectives, but some of the new tools outlined are at risk of contradicting elements of the criteria. For example, the robustness of totex benchmarking using FERC data is reliant on using comparable, consistent and normalised data to draw meaningful conclusions between FERC and the relevant networks. This is not possible due to insufficient information in the FERC data to normalise it to allow comparison – an issue acknowledged by Ofgem's own recognition that surrogate data may need to be used. Lessons should be learnt from Ofgem and National Grid's experience of development of the E3Grid benchmarking study which suffers from a lack of transparency and robustness due to the immaturity of the process. We recognise that totex benchmarking should be part of the regulatory toolset (and is a better guide than total cost or just using opex or capex benchmarking), but this should not be heavily relied upon in assessing efficient costs unless consistency and normalisation of data can be achieved. This is especially the case where it is not possible to split distribution activities from transmission activities in third party data. Such mixing of data sets can materially skew any benchmarking as shown by work we have undertaken in assessing publicly available data in this area. • Whilst we agree with the intention to benchmark future costs, it is not clear how this will be possible in practice. The lack of forecast data sets available in this area will make such analysis difficult. For example FERC data (referred to as one of the main benchmarking data sets) is historical only and there are fundamental issues in attempting to normalise this data for use in benchmarking. There is little other information available due to competition law requirements. As noted by Ofgem there are different nature and scale of Electricity TOs, so limiting future benchmarking to these comparatives will not necessarily work either. Historical benchmarking may have to be used as a proxy to give Ofgem enough information to assess costs. In this case results of mature benchmarking studies

	such as the International Transmission Operation and Maintenance Study (ITOMS) and the Gas Transmission Benchmarking Initiative (GTBI) should take precedence over any new studies which have not been tested. Our responses to the totex benchmarking questions below give more detail on these studies. • It is not clear how Ofgem will bring together the bottom-up and top down approaches. We agree that it will be beneficial to assess costs using both approaches but it will be necessary to explore areas where inconsistencies exist, rather than 'cherry picking' apparently efficient answers from different elements of analysis, creating an unachievable whole. Further detail in relation to the application of the cost assessment tools can be found in answers to the questions which follow.
Chapter 3	
1	**Are there any additional analytical techniques that we should consider beyond those we have used at past price control reviews to assess these factors?**
	With the energy industry about to go through the largest period of change since privatisation there is a definite need for Ofgem to consider that the future cannot follow trends of the past if carbon reduction targets are to be met. Coupled with a longer price control period and the enhanced investment requirements, this increases the risks faced by network companies. This will need to be reflected in the analytical techniques used for both real price effects (RPEs) and efficiencies in the RIIO-T1 period. **RPEs** Demand for key commodities and skilled resources is likely to be higher in the coming period than it has been historically in the energy industry. Supply of skilled resources especially is already low. With the impacts of climate change requirements and growth in renewable companies, this high demand and low supply will impact on future RPEs and likely generate price growth above that in the general economy. The start of this trend has already been experienced in the TPCR4 period. For example the capex allowances for RPEs given on an ex ante basis during the TPCR4 settlement only related to manpower and civil prices. No allowances were given for commodity prices. It is these commodity prices that have been considerably volatile during the TPCR4 period and caused difficulties in forecasting and responding to price movements. The techniques outlined in the document do not take account of this increasing demand and reducing supply. Instead of considering future challenges, it is proposed that the level of RPEs is assessed based on historical trends. Whilst we agree that these metrics should be considered in assessing RPEs, using only this data will downplay a fundamental uncertainty in networks' plans to 2021 and beyond. Assessment of future RPEs should consider readily available forward contract rates for commodities and electricity prices. It should also consider the differences between the general economy and specific industries, for example through use of more specific data in the Office of National Statistics (ONS) indices. Ideally consideration should be given to further analysis in this area. We welcome Ofgem's openness to having different RPE forecasts for specialist labour compared to general labour. We do, however, consider that the overall approach to RPE outlined throughout the consultation documents does not go far enough, and could impact on the ability of networks to deliver against future challenges. The onus for proving plan assumptions is rightly on the relevant network companies, however independent future data in these areas is at best contradictory and at worst non-existent. This gives rise to inherent uncertainty in the area that needs to be assessed as part of the regulatory process. Elsewhere in the consultation documents it

	is stated that Ofgem's minded to position is not to consider an uncertainty mechanism for RPEs. It is right that networks should be incentivised to deliver procurement efficiencies to achieve RPEs for commodities and labour at less than the market rates. However this incentive exists whether an uncertainty mechanism is in place or not. Consideration should be given to where the risk of large RPE increases outside the control of network companies (and not forecastable on an ex-ante basis) should be borne; either shared with consumers, or through a premium in the regulatory return to take into account this risk which is undoubtedly growing into the RIIO-T1 period. At present it is not clear that the principles of RIIO outlined in the document consider the interactions between cost assessment and uncertainties. **Efficiencies** From an efficiency perspective, the link to productivity metrics is a sensible one. We would welcome more clarity in the March document on how these will be applied in RIIO-T1 period. With an increasing baseload of work over the coming period, it must be recognised that costs will increase. Future efficiencies in Transmission will therefore help to mitigate this inevitable increase, so the application of productivity metrics needs to consider the delivery of more workload, rather than the same workload for less cost.
2	**Are there any additional data sources that we should be aware of to assist with our analysis in these areas? In particular, are there specialist labour indices that would be relevant for the gas transmission sector?**
	An historical data source not mentioned in the consultation document we are aware of is the Average Weekly Earnings (AWE) index from the ONS. This labour metric has replaced the Average Earning Index (AEI) and covers both overall industry movements as well as specific metrics for the electricity and gas supply industry. This more specific data could be applicable to a number of networks. We do not know of any specific labour indices for the gas transmission industry. Other data sources which would be worth considering are: • Forward contract rate curves for commodities, as outlined in our response to the last question • Any indices for labour in the renewable industries, as RPEs in these areas will influence those experienced in Transmission over the coming period
3	**Of the data sources presented in this chapter, are there some that you think we should rely more on than others?**
	Although both areas should be considered, specific industry data should be relied on to a greater extent than general economy data for both RPE and productivity to provide a more relevant assessment of factors affecting the network companies. This should apply to, for example, ONS data for both productivity and labour and EU KLEMS productivity data. Each metric has data for both with, in some cases, markedly different figures for each area. From a productivity perspective ONS data will be more applicable to UK regulated entities than the European based EU KLEMS data, which will be distorted by productivity improvements in less well developed European countries.
Chapter 4	
1	**Are our proposed cost drivers appropriate. Should additional drivers be tested?**
	We support the principle of totex benchmarking, as it should provide the desired outputs

at an efficient cost to consumers and overcome some of the organisational, structural and definitional problems inherent in benchmarking. However, given the high profile of the totex approach at RIIO-T1, it is crucial that the analysis is robust, and we are concerned that at present this may not be the case.

Effective normalisation between entities (through the use of relevant and applicable cost drivers) and data validation is essential to ensure benchmarking of data sets is robust. Only once these elements are in place will it be possible to draw effective and meaningful conclusions from the study. Given limitations presented by the FERC dataset and the inability to normalise key focus areas, we do not think this will be possible using this data set. We would therefore have concerns around using this method heavily in the regulatory process.

We are not aware of any suitable normalisation methods that can be used for the FERC data (due to the limits of the data set) but if a suitable data set can be found for totex benchmarking then consideration needs to be given to the following additional cost drivers:

- The impacts of growth in renewable generation on the transmission system as a driver of significant cost as networks adapt to the required changes. It is also likely to have an impact on unit costs through real price effects. If other companies in the data set either do not face these challenges or are already operating in a high renewable environment then results are likely to be distorted.
- It is important that Ofgem adjusts totex costs to reflect different levels of outputs proposed to be provided by different networks, as desired by stakeholders, otherwise companies responding to stakeholder wishes could be disadvantaged.
- Reliability of the relevant networks should be considered separately as a cost driver due to the material impact of changes to this output. It is arguably easy to perform well in cost benchmarking if lower reliability can be tolerated. The benchmarking studies we are involved with such as International Transmission Operations and Maintenance Study (ITOMS) and the Gas Transmission Benchmarking Initiative (GTBI) take these cost drivers into consideration.
- The relevant security of supply requirements and population densities of areas covered as this drives different planning or construction techniques and methods.

Overall if the totex benchmarking approach is to be pursued, we are pleased that Ofgem recognises that the results of its cost assessment will form (at most) the start of the conversation, rather than a mechanistic means of setting allowances**.**

2 Are there additional sources of data we could be looking to in order to increase the robustness of our analysis?

There are a number of existing targeted benchmarking studies, which have developed and matured over a number of years. These studies are sophisticated enough for the participants to rely on the results and use them in identifying and implementing best practice. Relevant examples include ITOMS, GTBI and International Comparison of Transmission System Operators (ICTSO) studies.

Chapter 5

1 Do you agree with our proposal to assess closely associated indirect operating expenditure alongside direct operating expenditure?

The document is not sufficiently clear in this area to allow a full understanding of how this approach would work in practice. On initial consideration of the detail provided we do have material concerns around adopting this approach. Whilst it would be beneficial for

Ofgem to focus more time on the material areas of direct opex and direct capex, there are issues which need to be considered before applying such an approach to the area of Transmission:

- Material issues in engineering support (covered by closely associated operating expenditure per the definition in the document) would be at risk of being ignored. For example, deliverability of the capital plan will be a key area in the RIIO-T1 period for all networks and will require arrangement of sufficient system access (an engineering support activity). The costs and justification for this will need to be specifically considered in the review, however it is not clear how consideration will be given in the approach outlined. This could mean that required and justified costs for strategies to facilitate more access and load related capex could be disallowed if the uplift on direct opex or direct capex is not sufficient. Other material RIIO-T1 areas covered by closely associated costs would include the work needed to obtain planning consents for our schemes, and designing the future transmission system. The level of work in both will increase into the RIIO-T1 period.
- There is a non-linear relationship between direct and closely associated engineering opex. An example of this is recruitment and training costs which will be required in advance of workload to allow for lead times of four years or more. A ‘smoothed’ allowance, based on a set uplift to direct costs, for expenditure such as this would risk necessary and efficient work being unfunded, and would not incentivise the right approach. Network companies should be encouraged to deliver the best value for money option for the future. In some cases, this will mean spending money in advance of direct work being delivered. Any cost assessments around closely associated costs need to take this into account.
- The non-linear relationship between direct and closely associated costs is true in any of the network companies, but the impact of such an assessment approach would be exacerbated in Transmission. Direct capex and opex for areas such as Distribution are by nature for higher volumes of similar packages of work. Work in Transmission is necessarily more bespoke and less ‘unitised’. This has two main consequences:
  - the uplift in costs for closely associated costs will be higher as there is less opportunity for economies of scale
  - the overall cost impacts of expenditure in advance of delivery is more marked.
- The consultation document suggests that this treatment of closely associated indirect costs has been used in previous regulatory reviews, but this has not happened previously in Transmission. It is not clear from the detail in the documents, or from reviewing price control documentation where this approach has been used, how exactly this would happen. We would welcome some practical guidance on how this will work.
- We do not manage our business in the way outlined in the document, so identification of closely associated indirect costs would only be performed for regulatory purposes. Recreating historical data to allow assessment over the last price control period will therefore be problematic, and we would need to implement changes to our accounting systems to capture this data going forwards, driving investment in IT systems. We are happy to work with Ofgem to make any process as smooth as possible, but in doing so we would encourage Ofgem to ensure that the data requested is beneficial and that unnecessary complexity in the reporting of such costs is avoided, and all reasonable alternative means of providing the required information are considered.

	• The document notes that this will be applied to TOs but is unclear whether the System Operator (SO) areas of Transmission would be covered. We assume that this is captured under the control centre expenditure which "may be better dealt with through fixed cost allowances", but would welcome clarity in this area in the March consultation document. If the main driver for any reporting changes is for comparability across network companies there will be inherent difficulties in achieving this for the SO functions due to their nature.
2	**Have we chosen the most appropriate mix of techniques from our cost assessment toolkit?**
	The mix of techniques is reasonable, but until more detail is available on the implementation of the techniques we will retain reservations on their practical application. More specifically and in addition to points made in relation to other areas, we agree that recent cost pressures in closely associated companies such as Electricity Distribution should form part of the assessment. We encourage Ofgem, however, not to rely solely on historical data as this is not a barometer for the future.
Chapter 6	
1	**Are there any additional business support costs that should be assessed?**
	We have no further suggestions for areas that should be assessed. In doing so we assume that definitions of the business support function used within Distribution assessments are maintained. As with closely associated costs, the document states that this approach will be used for TO business support costs. It is not clear how the SO business support costs are to be assessed. Within IS and Property especially, costs in these areas are largely driven by the resilience requirements for critical systems. These requirements are not prevalent in other areas and account for a significant proportion of SO costs. This makes benchmarking of these costs for the SO problematic.
2	**Have we chosen the most appropriate mix of techniques from our cost assessment toolkit?**
	Whilst we agree that benchmarking of TO business support costs should form part of the cost assessment process, we have a number of concerns about the consistency and normalisation of such a process across different network companies. As with totex benchmarking, the use of robust cost drivers to both normalise the data and ensure consistency of reported costs will be key to make any such assessment meaningful. More specifically on the regression analysis: • At present the cost drivers outlined in the document are specific to Distribution. Different cost drivers will need to be used if Transmission is to be compared on the same basis. For example the number of customers does not have the same impact on Transmission support costs as it does for Distribution. • Even once valid cost drivers have been identified there is also no reason to suggest that all support costs per driver will be the same across networks. For example, network length could be used for normalisation of costs but with the higher volumes of similar work in Distribution compared to Transmission, business support costs are unlikely to be comparable when normalised this way. There may therefore need to be another step in the normalisation process to take this into consideration. • Using only total direct costs as a driver will create an enhanced 'cherry-picking'

	effect. If cost is to be used as a driver we suggest using totex. • We do not believe that fixed plus current assets per the Balance Sheet represents a suitable driver. The fixed assets figures taken from historical cost accounts are distorted by age, and current assets are unsuitable for inclusion. A loan of £500m taken out the day before the year-end would add £500m to current assets, but would not affect the scale of the organisation at all. • We do not believe that employee numbers represent a suitable driver (with the exception of the subset of Human Resource activity) as they are strongly influenced by outsourcing arrangements and organisational structure. We have a number of further comments as follows: • Currently regulatory reporting is not consistent between the different network companies in these areas and will need updating to enable assessment in the manner outlined. Assessment of three years' worth of historical data will require restatement of previous annual regulatory reporting packs. Whilst the requirement for restatement is not ideal, we will work with Ofgem to undertake this work but with no definitions of the newly required data in place during TPCR4 (unlike Distribution), it will need time to ensure consistency. • Recruitment and training to ensure availability of skilled resources will be a material cost driver for Transmission over the RIIO-T1 period. Any assessment of business support costs will need to consider such costs separately to ensure appropriate focus is maintained in this area. • We support the idea of expert review for specialist areas including IS and Property, however, given the specialised nature of Insurance, we suggest these costs should also come under expert review to consider the appropriate cost and consumer risk balance in the area. • We believe it is important that infrastructure and security IS capex are assessed together with IS opex costs. The potential for capitalisation and organisational issues to distort the analysis are especially significant in this area. • For property, rent or buy / sell choices must be adequately normalised in the benchmarking to ensure robustness of the benchmarking. We are concerned that network companies which rent property could be disadvantaged compared to others which have bought property. Any assessment should consider that either approach may be the most efficient depending on the individual circumstances at the time. We suggest that expert analysis of property costs should include, for those network companies that own property, an assessment of what the notional rental would be on those sites, which also needs to be reflected in the totex analysis.
Chapter 7	
1	**Do you agree with our proposal to assess closely associated indirect operating expenditure alongside capital expenditure?**
	Please see our answers to Chapter 5, Question 1 above.
2	**Have we chosen the most appropriate mix of techniques from our cost assessment toolkit?**
	The mix of tools outlined in the document is reasonable. The use of historical trend analysis is clearly useful, however care should be taken when using it to assess the costs into an uncertain future with necessarily higher delivery rates. Linking cost

	changes to impacts on outputs is a useful way of presenting this provided it can be done in the context of a changing workload. Regarding benchmarking of non-load related investment, we agree there is a limited amount of data available. The suggestion of using closely related industries is welcomed, as attempts to use more general data will result in a lack of robust analysis. We agree that clear and early definitions of unit cost scopes are an essential starting point for this kind of comparison exercise. We agree with the view that volume analysis relating to non-load related investment can only be reasonably performed using condition and appropriate criticality assessments. Assessing the unit costs for non-load related investment is challenging for NGG due to the very small numbers and high variability of some of our asset types. Even for NGET, the small volumes (relative to the DNOs) and site specific challenges make quantification of unit costs difficult. We are committed to work with Ofgem to develop the most appropriate methods to assess the costs related to our assets. We also welcome the proposed expert review in these assessments, as this will ensure the challenge and review of our business plans is appropriate. Finally, the proposed project-by-project review should be proportionate to the scale of project selected to avoid unnecessary burden on both network companies and Ofgem resources. Please also see our response to Chapter 5, Question 2.

Outputs and incentives

Chapter 1	
1	**Do you have views on the approach we have undertaken to developing the outputs framework?**
	We have been fully involved in the Ofgem-led stakeholder workshops at which the development of the outputs framework has taken place. These sessions have provided a very useful environment in which to develop ideas with other network operators, other stakeholders and Ofgem. Overall, the development of the outputs framework is currently lagging behind Ofgem's original plan. This is not surprising given the scale of the task and the associated limited timescales, together with the parallel activity of a TPCR4 roll-over submission for transmission. Given the importance of the change to the RIIO framework and the critical part that the identification of outputs plays in this, it would be better to take additional time ahead of the submission of the first well justified business plan to ensure that the outputs and associated incentives are fully developed and supported with adequate analysis from network companies and stakeholders. In light of this, it may be better to consider the July 2011 submission as a stepping stone to the submission of a fully developed well justified business plan in March 2012.
2	**Do any of our proposed output measures present potential difficulties in ensuring the submission of accurate and comparable data?**
	The main difficulties that we foresee are around the losses caused by transmission owner activities, wider reinforcement boundary capability and constraints caused by transmission owner activities. For each of these, outputs cannot be directly measured and some offline modelling is required. Whilst this should still be possible, it is important that sufficient time is devoted to establishing consistent definitions to be applied by each of the network companies. Customer satisfaction is another area that is potentially difficult to measure, although we are comfortable with the proposals which acknowledge the subjective nature of customer satisfaction and stakeholder engagement performance.
3	**Are there any aspects of our proposed outputs framework where the reporting requirements are likely to lead to disproportionate regulatory costs?**
	Without further development of the relevant outputs, it is difficult to be definitive about reporting areas which may lead to disproportionate regulatory costs. The areas of most concern are wider reinforcement boundary capability and network output measures since there is a risk that the framework will collapse to input-based regulation in these areas. This would stifle innovation and prevent network operators from optimising resources and outage requirements across the complete capital plan leading to increased costs. It is therefore vitally important that further development in these areas is cognisant of this risk.
4	**Do you have any views on whether in principle it is appropriate to consider requiring the companies to do more to verify their regulatory reports?**

	It may be possible to address any issues regarding the regulatory reports with the further development of the outputs and therefore it is not possible to provide firm views until this further development is completed. Clearly, any additional costs would need to be justified against the value that is added for consumers.
5	**Should we introduce an independent examiner for the TOs to improve regulatory reporting?**
	As above, it may be possible to address any issues regarding the need for an independent examiner with the further development of the outputs and therefore it is not possible to provide firm views until this further development is completed. As above, any additional costs would clearly need to be justified against the value that is added for consumers.
Chapter 2	
1	**Do you have any views on the primary output and secondary deliverables for electricity and gas transmission safety?**
	We agree that the safety output measures should support rather than duplicate the function of the HSE and therefore the proposed primary output and secondary deliverables appear appropriate.
2	**Are these appropriate areas to focus on and are there any other areas that should be included?**
	Whilst we agree that the proposals involve appropriate areas of focus, we are also considering other areas which could be covered with the definition of leading secondary delivery indicators. Potential examples include process safety and training. We intend to develop these potential options as part of our well justified business plan.
3	**Do you agree with the proposed approach to setting safety incentives?**
	We agree that it is not appropriate to attach financial incentives to the primary safety outputs since we are incentivised by other agencies and mechanisms, particularly the HSE. We also agree with Ofgem's initial view that it would be inappropriate to apply additional penalties in circumstances where network companies do not meet their legal safety requirements for the reasons set out in the consultation document.
Chapter 3	
1	**Do you have any views on the primary output and secondary deliverables for electricity reliability and availability, including:** **(1) are these appropriate areas to focus on?** **(2) are there any other areas that should be included?** **(3) do you agree with the proposed approach to setting reliability incentives?**
	We agree that a combination of primary output and secondary delivery indicators are required to adequately monitor reliability and availability. The appropriate primary (lagging) reliability outputs are Energy Not Supplied (ENS) and constraints since they directly measure the impact of unreliability on customers. Constraints are already incentivised under the System Operator control. This provides

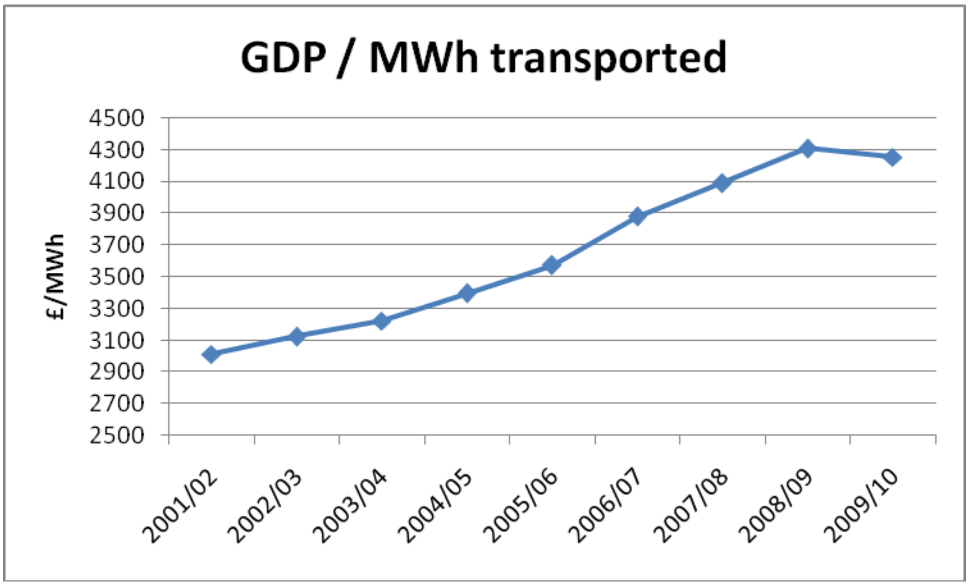
the appropriate reliability and availability incentive in England & Wales, where National Grid is both System Operator and Transmission Owner, and we agree that the arrangements in Scotland should be reviewed to ensure that, where practical, the Transmission Owners have the appropriate incentives to consider constraint costs.

In terms of setting reliability incentives, the key parameters of the ENS scheme are the baseline and the incentive strength.

The proposed approach to setting the baseline appears to involve companies making a proposal as part of a well justified business plan which will then be considered and, if necessary, changed by Ofgem. It would be helpful to better understand the issues that Ofgem would include in considering whether the baseline proposed by the companies are acceptable or need to be changed.

On incentive strength, we agree that the current incentive strength of approximately £33,000 per MWh is above the value that customers place on being without supply. Other than noting that a value in the order of half this strength would still be above value of lost load in other jurisdictions, the consultation is unclear about how this issue will be resolved. We anticipate that stakeholder engagement on networks business plans and the fundamental review of the security standards should provide useful evidence to support this debate.

In order to better understand the economic value of lost load, we have also compared Gross Domestic Product with MWh transported in GB, and plotted the result on the graph below.



Whilst this is a simplistic measure of the value of lost load, which has its limitations (e.g. it assumes that all MWh transported contribute to GDP, it does not take account of the cost of disruption caused by loss of supply events or the potential for industry to catch up lost productivity when supplies are restored) it may provide a useful benchmark for further discussions.

Secondary (leading) delivery indicators are required to ensure that asset health related network risk is being appropriately managed. The TOs jointly developed a set of measures ("Network Output Measures" or NOMs) to meet the requirements in Standard Condition B17 and Ofgem's subsequent six Specified Amendments (conditional approval letter from Ofgem dated 18 December 2008). The TOs spent three years developing these proposals with Ofgem and further time embedding them into their businesses, with final Ofgem approval granted on 31 March 2010. Whilst we appreciate the need to evolve NOMS over time, we do not agree that the majority of the changes as proposed

	add value to the customer. A summary of Ofgem's suggested changes to the Network Output Measures Methodology is presented below, with our comments: 1. *A global change of priority ordering from lowest "1" to highest e.g. "4".* We consider this to be counter-intuitive; most people would interpret a 'number one priority' as the most important and urgent issue to address. 2. *A change in the definitions of Asset Health Indices.* We agree that using year-based measures for both Asset Health Indices (AHIs) and Replacement Priorities is confusing. We therefore do not object to moving away from the 0-2 years, etc, scale for AHIs. However, the proposed categories are not clearly defined and we would therefore wish to retain our detailed definitions for Asset Health Indices which can be consistently mapped to the existing Ofgem definitions. 3. *A change in the Replacement Priority definitions.* We find the year-based system helpful to communicate how we build a capital plan and would therefore wish to retain it for Replacement Priorities. The word "Risk" is open to wide interpretation and again we would wish to retain our currently agreed detailed definitions. Otherwise, work would have to be re-started to identify consistent definitions, and to define how Criticality will be applied to Health Indices to assign Risk ratings. 4. *Forecast of System Availability as a secondary deliverable*. We are concerned about forecasting overall network availability. Forecasting of actual availability is extremely complex as it incorporates actions of the System Operator, including moving system outages or utilising a contracting option to manage constraints. It is unclear how forecasting availability provides a long-term benefit to the customer as the level of availability is a balance of many factors. 5. *Reporting of faults and failures as a secondary deliverable*. We agree that a forecast of faults/failures is inappropriate given the low number of events. Unnecessary changes to the Asset Health Index and Replacement Priority definitions would potentially result in our not being able to utilise the two years of historic information already provided to Ofgem because a clear mapping between the current and proposed definitions does not exist. In addition, without further significant work, the proposed new definitions no longer ensure comparability between the TOs. This was a clear requirement from Ofgem throughout the development of the Network Output Measures and significant effort has been expended by the TOs to achieve this.
2	**Do you have any views on our proposed treatment of different loss of supply events when calculating ENS including:** **(1) events lasting three minutes or less?** **(2) events that cause electricity not to be supplied to three or fewer directly connected parties?** **(3) events resulting from actions to ensure public safety, third-party damage, severe weather and other exceptional events?** **(4) planned outages?** **(5) events on an adjacent system?**
	We agree with the proposed treatment of events lasting three minutes or fewer. These events do not account for a significant volume of ENS. Since they occur even when delayed auto-reclose equipment operates correctly to clear faults caused by adverse

	weather, their inclusion is essentially an incentive based purely on the weather. We agree that, ideally, the exclusion relating to unsupplied energy to three or fewer directly connected customers should be amended to reflect only those customers that have requested lower standards of connection. Three or fewer customers has been used as a proxy for lower standard connections that have resulted from a customer's choice. Given the relatively low number of these connections, the proposed change more accurately reflects ENS whilst not adding significant burden. Our only concern with this approach is that it may complicate the benchmarking of historical performance. We are currently assessing this historical data. We agree with the proposals to require TOs to demonstrate that ENS resulting from actions to ensure public safety, third party damage and other exceptional events were a consequence of an external cause and all reasonable steps have been taken to minimise the impact. We are obviously concerned that any learning from the application of the DNO licence condition reflecting these requirements is utilised in the transmission scheme for RIIO-T1. We would be interested to understand the reason for the difference between the extreme weather event definition for National Grid and the Scottish Transmission Owners. Given the definition of the boundary between transmission and distribution in England and Wales, the demand at Grid Supply Points is sufficient to justify sufficient redundancy to ensure that there is no energy not supplied as a result of planned outages. For directly connected customers, planned outages can lead to energy not supplied, however in these cases, customers have specified a lower standard of connection and therefore any energy not supplied would be excluded. We are comfortable with the proposals for events on adjacent systems and look forward to contributing to the further development of the associated framework.
3	**Do you have any views on our proposed options for applying financial consequences in the case of material under or over-delivery of secondary deliverables?**
	It is essential that material under- or over-delivery of secondary deliverables is measured against the profile of asset replacement priorities (based on asset health and criticality) at the end of the RIIO-T1 period. This maintains the incentive on networks to innovate where possible in order to achieve the required profile of asset replacement priorities at the minimum cost. If delivery is measured in terms of a volume of asset replacement only, then this incentive is removed to the detriment of customers. Both of the options for applying financial consequences in the case of material under-delivery need to be developed such that they are consistent with the wider incentive arrangements, and in particular any changes to the efficiency incentive rate. For the second option, the consultation document describes an example in which a TO has under-delivered in RIIO-T1 and has to fund the shortfall between their forecast and what they actually delivered in RIIO-T2. It should be noted that the savings associated with the shortfall in RIIO-T1 would be shared between the TO and customers in accordance with the efficiency incentive rate. This would need to be considered in agreeing the shortfall that the TO would need to fund in RIIO-T2 if the efficiency incentive rate changes. It would appear appropriate to achieve symmetry between the treatment of the financial consequences of under- and over-delivery assuming, as noted in the consultation document, that the TO can demonstrate that the over-delivery was in customers' best interest.

4	**Do you agree with our proposed approach to incentivising the TOs for the impact of planned outages on constraints, including: (1) is it appropriate to incentivise TOs? (2) if so, should the incentive be broadened to other areas - for example, unplanned interruptions? (3) are the confidentiality issues around constraint costs material and if so, how might they be resolved? (4) is there a need to review the procedure for incorporating the full cost of cancellation to the TOs?**
	In principle, constraint costs attributable to TOs actions should be incentivised. This would allow TOs to efficiently trade-off the costs associated with all options to minimise the impact of planned outages with the associated constraint cost consequences and achieve a plan which is in the best interests of consumers. It should be noted that the current arrangements which allow the SO to make outage change payments to the TOs described in the consultation are currently under development. These arrangements provides a mechanism for TOs to recover the cost of options to minimise the impact of planned outages, although it is unclear whether this incentive is sufficient to drive TOs to consider all available options. It clearly does not expose TOs to the impact of delaying the return of a circuit following an outage. Whilst we support the pass-though of a portion of the SO incentive onto the TOs in Scotland in principle, there are clearly a number of significant practical issues that would need to be addressed. Whilst it could be argued that the confidentiality issues are currently material, this area is being reviewed by the industry under the Commercial Balancing Services Group, a group related to the CUSC Balancing Services Standing Group[17]. Given that this work is already in train, it does not appear that the confidentiality issues are insurmountable. The question of whether the incentive should be broadened to other areas such as unplanned outages will depend upon the complexity of the arrangements. Constraint costs caused by unplanned outages are not particularly material, and therefore broadening of the arrangements is only reasonable if this can be achieved with minimal burden. We would welcome the opportunity to explore the options for developing a pass-through mechanism with the transmission owners, Ofgem and other stakeholders. We agree that it would also be appropriate to review the procedure for incorporating the full cost of cancellation to the TOs in light of the issues raised in the consultation document.
Chapter 4	
1	**Do you have any views on the primary output and secondary deliverables for gas reliability and availability: (1) are these appropriate areas to focus on? (2) are there any other areas that should be included? (3) do you agree with the proposed approach to setting reliability incentives?**
	The primary output identified is appropriate given the level of incentivisation that already exists for gas transmission reliability and availability. We have some concerns about

[17] Further details are available here:
http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/workingstandinggroups/bssg/index.htm

	extending the incentive arrangements at exit into RIIO-T1 without review. At the very least, we would expect the return on regulatory equity (RORE) analysis to be used to assess the impact of the caps and collars on each of the incentive schemes. Investment to meet the flexibility requirements of gas transmission customers is likely to be a significant issue over the RIIO-T1 period and therefore it is essential that the associated outputs and deliverables are developed and implemented. Whilst this output may allow the obligations on the NTS with regard to flexibility to be better defined, there will also be a requirement for a mechanism to provide funding to complete the associated reinforcements. We would expect this to take the form of an uncertainty mechanism similar to those set out later in the consultation for electricity wider reinforcement works. We will continue to work with Ofgem and our stakeholders to better develop the network flexibility outputs and deliverables as we develop our well justified business plan. The secondary deliverables for asset risk identified in the consultation still require further development to optimise their form for the price control, however we believe this is achievable in the timescales set out.
2	**Do you have views on whether additional transparency and separation should be provided between the TO and SO roles?**
	The relationship between the Transmission Owner (TO) and the System Operator (SO) is vital to the efficient operation, maintenance and development to the gas transmission system. Only through the effective combination of operational experience and intelligence, coupled with the maintenance and development strategies of the network itself, can efficient decisions be made relating to the NTS. This relationship facilitates an effective balance between constraint costs (i.e. operating risk) with development costs (i.e. financial risk). The anticipated operating risk following signals for incremental capacity has a direct bearing on the assessment of whether to build additional capability into the network. However, if knowledge of the operating risk were to be published it would allow industry participants to take advantage of existing constraints to the detriment of other stakeholders. Therefore, we believe this information should not be made publicly available. Operational experience has demonstrated to the SO that changing use of the existing capacity in the NTS is creating issues when managing geographical gas supply and demand mismatches. These issues are not triggered through any auction signal or investment driver, so in isolation the TO would not be aware of the issue and would therefore not be working towards resolving it in a timely manner. Other benefits from a close TO/SO relationship include: • Effective system outage planning and management, and commissioning of new assets. This is increasingly important through a period of heightened capital investment. • Inclusion of the SO's experience and knowledge of delivery factors in the TO's future designs • Optimisation of operating strategies through changes to network configurability. For example, modifications to key compressor stations to allow gas flow in different directions. • Helping to reduce resource constraints • Providing a single accountable agent Enhanced understanding of the costs driven by network user behaviour from the SO, allowing better reflection of efficient totex pricing to encourage optimum decisions by all parties.

Chapter 5	
1	**Do you have any views on the environmental outputs outlined?**
	The environmental outputs outlined provide a good starting point for RIIO-T1, although there are a number of key issues to be addressed ahead of the decision document in March, in particular the inclusion of a broad environmental primary output. As part of our initial RIIO-T1 stakeholder engagement, many stakeholders have noted the materiality of our role in facilitating the decarbonisation of the generation sector compared to the limited scope we have to reduce direct emissions. Since the understanding of environmental impacts is likely to improve significantly during the RIIO-T1 period, consideration should be given to arrangements which allow internalisation of other environmental costs during the period.
2	**Are these the appropriate areas to focus on and are there any other areas in which primary outputs and secondary deliverables should be set?**
	The areas of focus are appropriate, and the split between broad environmental objectives, direct emissions and wider network impacts is helpful. As part of the development of our well justified business plan, we will investigate whether there are other direct network emissions which should be covered with a primary output or secondary deliverable. This will be achieved by comparing candidate outputs against the criteria set out in the RIIO handbook.
3	**Do you agree with the proposed approach to setting environmental incentives?**
	We agree with the approach to setting environmental incentives, which is in line with the principles set out in the RIIO handbook. In particular, it is important to take account of the network companies' influence over the output when setting financial incentives.
4	**Do you have any views on what the TOs 'full role' in a low carbon economy may involve by the year 2020?**
	We agree that TOs will have a crucial role in the transition to a low carbon economy, and that this will extend beyond traditional activities to seeking new opportunities to facilitate a move towards a low carbon economy. The RenewableUK policy paper which is referenced in the consultation document provides a list of illustrative examples which is useful in setting the scene for the types of activities that could be included. Given the extent of change required, it is unlikely that a full list of TO activities could be accurately forecast at this point, which adds weight to the arguments in favour of a broad environmental primary output which would provide TOs with the scope to innovate.
5	**What role is there for a primary output in RIIO-T1 on TO's contribution to the UK's environmental and energy objectives and what type of incentive would be most effective to drive TOs delivery in this area?**
	In light of the above and the relative impact of progress in this area on national carbon emissions, there appears to be a clear justification for a primary output with a reputational incentive in this area. There may also be a case for a financial incentive, although there are a number of practical issues which would first need to be addressed. These issues are discussed

	further below.
6	**Do you have any additional views on RenewableUK's proposal for a specific low carbon economy output including the form and size of such a reward mechanism?**
	The RenewableUK proposal and supporting policy paper provide a straw man for an output and financial incentive based on progress/contribution towards renewable and low carbon policy milestones. The policy paper notes a number of the issues which need to be addressed. We would prioritise further consideration of the consumer benefit and the interaction with other primary outputs, although this is complicated by the delay to the development of the connections outputs caused by the Project Transmit interaction. Further development in these areas should facilitate a better understanding of the appropriate form and size or any reward mechanism.
7	**Do you have views on the relative roles of the TO and SO in relation gas shrinkage and venting, and how we might align the incentives between the two parties?**
	In terms of gas venting, it may be possible to disaggregate that which is driven by the activities of the TO in completing maintenance, and that which is driven by the activities of the SO in depressurising compressors for safety reasons when they are not in use. For shrinkage, this is much more difficult because the counter-factual network would be difficult to establish. In addition, it should be noted that TO investments to reduce shrinkage need to be assessed over the whole life of the asset and therefore incentives based on a relatively short period of time can potentially paint a misleading picture of the value of the investments. The well justified business plan could instead be used to set out the approach to optimising investment and shrinkage.
8	**What incentives should companies face to manage their carbon footprint?**
	National Grid is committed to managing the impact of our activities and therefore fully supports the introduction of a primary output to report on scope 1, scope 2 and scope 3 emissions with as wide a scope as possible.. This output is listed under Electricity Transmission in the consultation document, but we would be happy for this to be extended to cover our Gas Transmission activities. It is important that Ofgem's reporting requirements for should align with the form and structure of any Government reporting requirements to avoid unnecessary complexity. The use of a reputational incentive is a pragmatic step as companies' understanding of their carbon footprint improves, although this should be reviewed at the RIIO-T1 mid-point. We would hope that reporting arrangements have developed such that a financial incentive could be considered at that point.
9	**What incentive should be put on TOs in relation to losses?**
	National Grid is committed to optimising the level of losses on the electricity transmission network as part of the development of an economic and efficient network. As highlighted later in the document when describing a utilisation incentive scheme (para 8.75), incentives based on a short-period of time (a price control period) can potentially paint a misleading picture of the value of investments on assets which have a much longer life (in the region of over 40 years). This suggests that the incentive scheme for the losses primary output would need to operate over a period of time that is significantly

	longer than the price control period. This may limit effectiveness and credibility. We also note the complexity that would need to be introduced in order to establish the elements of transmission losses that are controllable by Transmission Owners. This is likely to require network modelling in order to disaggregate the impact of SO and TO performance. This is also likely to require the establishment of a baseline which will be based on a particular demand and generation background. Given the complexity of these issues, and the relatively small impact that Transmission Owner investment decisions are likely to have on transmission losses, it would be more appropriate for network companies to set out their approach to optimising the level of transmission losses in their well justified business plans. This could be part of the establishment of the network planning policy (para 8.67 refers). This would also address the issue of perverse impacts on network development raised below.
10	**What are the options to avoid any perverse impacts on network development to connect renewable generation?**
	As described above, this issue can be addressed using the well justified business plan rather than an incentivised primary output. If an incentivised primary output is required, then it will be necessary to establish a baseline forecast of transmission losses during the price control review. A mechanism will then need to be developed to address changes in the demand and generation background away from this forecast.
11	**Do you agree with the principle of full internalisation of environmental costs? To what extent should the output for SF6 move towards this objective?**
	We support the principle of full internalisation of environmental costs where practically possible and therefore changes to the SF_6 incentive which move towards this objective. The proposed change from a target leakage rate to a target level of SF_6 leaked emissions would be appropriate if decisions between air-insulated (AIS) and SF_6 gas-insulated (GIS) switchgear were based on a cost benefit analysis and as for losses above, the incentive ran beyond the price control period. In all cases, however, this decision is based on practical site issues with SF_6 only chosen if there are environmental pollution or spatial restrictions. In light of this, a move to a target level of emissions would need to include adjustments to the baseline for additional SF_6 switchgear to avoid decisions to meet our other objectives being penalised under the scheme. When setting this target, each network's inventory of GIS switchgear would need to be considered including the respective ages and associated IEC leakage rates. If these issues can be satisfactorily assessed, then the proposed change in the structure of the incentive to make it a marginal incentive based on the non-traded value of carbon appears to be appropriate.
Chapter 6	
1	**Do you have any views on the primary outputs outlined for customer satisfaction?**
	As noted in the consultation document, National Grid has recently been developing quantitative and qualitative customer surveys. This has proved to be a very useful exercise which has revealed some valuable information about our customers' priorities. We are therefore comfortable with the use of a customer survey as a primary output and look forward to working with Ofgem and other stakeholders to develop our current surveys as necessary.

	National Grid is also committed to ongoing stakeholder engagement and therefore welcomes the recognition of this activity with a primary output. The use of a discretionary reward appears appropriate given practical issues associated with regularly and consistently surveying the very wide range of National Grid's stakeholders. We also support Ofgem's proposal to make competent complaints handling a reputational measure and a pre-requisite to stakeholder engagement rewards. This appears to represent a pragmatic approach given the different relationship between transmission and end consumers.
2	**Are these the appropriate areas to focus on and are there any other areas that should be included?**
	We agree with the proposed areas of focus. We note that an annual discretionary reward for stakeholder engagement may not adequately cover the wide range of stakeholder engagement activities that National Grid currently performs (e.g. Transporting Britain's Energy, Seven Year Statement, Connections seminars and quarterly updates, Offshore Development Information Statement, etc.). We intend to identify the costs and associated stakeholder engagement outputs as part of the development of our well justified business plan. If appropriate, we will propose secondary delivery indicators to cover these additional stakeholder engagement outputs.
3	**Do you have comments on the proposed approach to setting incentives related to the customer satisfaction outputs?**
	An incentive arrangement which recognises both absolute and year-on-year performance is appropriate and we agree that further engagement with stakeholders will be required before the parameters of the incentive are set. We are keen to start the incentive in 2013/14 as proposed in the consultation document, although we note that it will be important to have sufficient data to set a meaningful baseline, and that the amount of data available is likely to depend on the scale of change required to the current survey. It is likely to be difficult to identify an economic value for customer satisfaction and therefore setting the slope of the incentive is likely to be challenging. In order to assist with this process, we will seek to identify the cost impact of initiatives to improve customer satisfaction as part of the development of our well justified business plan.
4	**Should the incentives apply to National Grid for good performance as system operator as well as in its transmission operator role?**
	National Grid is committed to delivering excellent levels of customer satisfaction across both the Transmission Owner and System Operator parts of the business. We would therefore be more comfortable with measures which are consistently applied across both parts of the business.
Chapter 7	
1	**Do you have any comment on the key principles we have identified for the delivery for connections?**
	We agree that delivery of connections to the timescales set-out in the existing codes could be a primary output. We also support the information gathering from customers that is part of this consultation

	and the joint Project TransmiT and RIIO-T1 consultation letter. This should inform the further development of connections outputs, including the question of whether the success of the connect and manage regime can currently be measured.
2	**Do you have any comment on the interactions with the other workstreams, in particular Project TransmiT, for electricity transmission connections?**
	As set-out in our response to the joint Project TransmiT and RIIO-T1 consultation letter, we believe that there would be merit in exploring changes to both the commercial and regulatory regimes to provide a 'menu' approach whereby different timescales could be offered to different types of connection. The range of connections that we are currently processing suggests that the use of an average approach would not be helpful. In our response to the uncertainty mechanisms consultation, we also note that any change to the classification of connection assets as part of Project TransmiT may change the price control costs associated with the provision of connections.
3	**Do you have any views on the existing arrangements for gas transmission?**
	As part of our ongoing engagement with customers, we have identified issues with the lack of defined timescales associated with the gas transmission connections process. In order to address these issues, we are currently working with our customers to develop revised arrangements.
4	**Do you consider any specific obligations and /or incentives are required for gas transmission?**
	The provision of connection within prescribed timescales is already obligated as part of the gas transmission arrangements. As part of RIIO-T1, it will be important to ensure that the associated obligated timescales are consistent with the requirements of the planning regime.
Chapter 8	
1	**Do you agree that there is a need for secondary deliverables that relate to wider reinforcement work on electricity transmission networks?**
	The timely completion of wider reinforcements is crucial to the economic and efficient operation of the transmission network, and therefore we strongly agree with the need for secondary deliverables that relate to wider reinforcement work.
2	**Do you agree with our proposed approach to the specification of these secondary deliverables?**
	We agree with the proposal to use boundary capability in preference to the delivery of specific assets since this provides more opportunity for transmission owners to innovate in delivery. Further work will be required to ensure that a consistent and objective measure of boundary capability is developed and agreed with stakeholders.
3	**How should we encourage timely delivery and deal with non-delivery?**
	We agree with the proposal to link the financial incentive associated with delays to delivery with the constraint costs arising from these delays. As noted in the consultation document, in England & Wales this could be achieved with greater consistency between SO and TO incentives; this is consistent with the RIIO framework.

	We are slightly confused by the proposals for non-delivery or agreed delays. If the delay is in consumers' interest, then to claw-back the full avoided costs would be inappropriate since the efficiency incentive rate would mean that these avoided costs would have been shared with consumers. The consultation document questions whether the arrangements should provide a reward to companies for not progressing with reinforcements that turn out to be unnecessary. This appears appropriate but we agree that careful design is required to avoid incentives to include unnecessary projects in our plans. The consultation document also notes that if TOs can demonstrate that deferral of the project into the next price control is in consumers' best interests then additional funding would not be forthcoming for the next price control to prevent consumers from paying twice. Again, this proposal needs to be cognisant of the operation of the efficiency incentive rate and in particular any changes to the efficiency incentive rate between price control periods. We would welcome the opportunity to further develop these complex arrangements with Ofgem and other stakeholders.
4	**Have we identified appropriate options for bringing flexibility, over the price control period, to the secondary deliverables that TOs should deliver and to the revenues that they receive for this delivery? Which options work best for consumer interest? How would this depend on the circumstances?**
	We welcome the proposed secondary deliverables for wider reinforcement works set out in the consultation document, which represent a pragmatic step forward. In considering potential secondary deliverables, it is necessary to achieve the appropriate balance between options which involve significant administrative burden and risks of micro-management and options which involve levels of risk which are too high for networks and/or Ofgem to contemplate. Option (a): trigger mechanisms calibrated at the price control review would appear to bring benefit to consumers. Administrative burden and risks of micro-management are minimised because the trigger is specified ex ante and applied mechanistically. The network's incentive to innovate remains and the network's overall resource and cash-flow optimisation is not contingent on Ofgem decision-making. Option (b): within period determinations to approve further deliverables also has the potential to bring benefit to consumers. We note that the administrative burden and risks of micro-management are higher than for the other options and therefore we would initially expect this option to be used in more exceptional circumstances. We also note the additional obligations associated with scheme development and an up-to-date network development plan and welcome the acknowledgment of the associated costs. Option (c): network planning policy and volume driver agreed upfront appears to provide the most potential to bring benefit to consumers. This is because it offers the minimum administrative burden and risk of micro-management and therefore the maximum discretion for networks. This provides the maximum opportunity for networks to innovate and optimise overall resources and cash-flow. The key to the success of this option is the network planning policy, and the way in which some of the potential concerns noted with option (d) (e.g. potential time lag between build and utilisation, success of generation and demand forecasts) are addressed.
5	**Do you agree with our plan to not develop proposals for an asset utilisation incentive scheme (option (d)), and to focus, instead, on the other options?**
	We note the potential concerns associated with option (d): company discretion subject to utilisation incentive scheme, and in particular those associated with an unacceptable level

	of risk and consequential cost for consumers. We disagree that the financial incentive is simply a way to improve generation and demand forecasts, since there is considerable scope for innovation in the design of the optimal network reinforcements. We intend to explore incentive options which could provide mitigation against the risks identified whilst providing further incentives to innovate and reducing administrative burden as part of the development of our well justified business plan.

Business plans, innovation and efficiency incentives

Chapter 2	
1	**Do you have comments on the description of the form and structure of the price control?**
	We broadly agree with the form and structure of the price control.
2	**Is the scope of the price control including the range of services excluded appropriate?**
	Not applicable to Transmission – please refer to National Grid's Gas Distribution response.
3	**What are the appropriate criteria for assessing whether a proposed change to the revenue profiling is appropriate?**
	We note Ofgem's preference to set base revenue for each year of the price control consistent with the expected path of expenditure requirements. This approach has the advantage of being transparent as the base revenue is equal to the sum of the parts of the components going in to the revenue calculation, with no phasing adjustments. By contrast, a profiled revenue stream has the advantage of removing volatility for companies and consumers alike. We would therefore suggest that the volatility of charges with and without a change to revenue profiling should be one of the criteria. In addition to this we would add financeability considerations. Amendments to the profile of revenues can play a part in ensuring that appropriate equity and credit metrics are achieved and that the overall price control package is financeable. We note in paragraph 2.27 a proposal to use a discount rate consistent with interest rates on low risk investments rather than the WACC. We believe the only appropriate rate to use is the WACC. Ofgem has a long history of profiling revenues using the allowed WACC on the grounds of NPV neutrality. To change to a different rate now is unjustified and would represent a significant departure from regulatory precedent.
Chapter 3	
1	**Are you content with the degree of guidance we are providing on a well-justified business plan? Is there additional guidance you would value?**
	As this is the first time network companies have been required to submit well-justified business plans, we expect that the collective understanding of what constitutes such a plan will evolve throughout the price review process. Undoubtedly network companies will learn from this collective experience, and we therefore look forward to open discussions with Ofgem on how our proposed plans compare to Ofgem's expectations of a well-justified plan as we progress through the process in order that we can meet or exceed requirements in this area. During these open discussions with Ofgem, we would welcome further guidance on

	the link between uncertainty mechanisms and the forecasts within the plan. Current guidance surrounding the well-justified business plan seems to cover the increase in evidence around costs or details required for justifying uncertainty mechanisms. We would welcome discussion on how the regulatory assessment will consider these together to ensure that future requirements are most efficiently funded given the increasing range of uncertainty into the future.
2	**Do you have comments on the use of ten years as the basis for forecast data? What level of detail should additional five years data to place this forecast into context be? Where might a longer period be appropriate? Are there cases where ten years would be problematic? If so what alternative approach might we follow?**
	We agree with the use of the proposed ten years data (i.e. to 2020/21) for plans under the RIIO regime of an eight year price control period. In assessing the ease of producing forecasts there is a distinction between areas within the control of network companies and others where external impacts can materially alter the plan. As forecasts are extended, the impact of external factors on many areas of the plan becomes greater. For example, load related capital investment, which is driven by requirements of customers; also a number of areas within Networks' forecasts are reliant on third party data. This means that any long-reaching view of the future is more uncertain, increasing the risk to network companies, in particular in the outer reaches of the business plan. By considering outputs and uncertainty mechanisms, the principles of the RIIO regime recognise these impacts. Similar principles should apply in assessment of both the ten year forecasts and, if required, the additional five years' worth of data. The longer period of forecasts should be focused in areas that are material and within the control of network companies. For example, it should be possible for network companies to give a forecast for: • Asset replacement volumes based on current policy and knowledge of assets • Maintenance volumes These are both material areas and largely within the control of network companies (although some assumptions will have to be made to give this view). Expected generation and demand forecasts could also be supplied, which would give a high level indication of the assumptions underlying the plan alongside alternative scenarios and the impact these may have on potential load-related investment requirements into the future. This is particularly important in light of the uncertainty facing transmission networks in supporting the decarbonisation of the generating mix and the anticipated developments within the distribution networks. In contrast, the prices of activities are subject to external impacts (costs of labour, commodities etc) which would be increasingly more difficult to forecast as the time period extends. Similarly load related capex, wider system reinforcements and the related impacts on opex are not completely within network companies' control, so any view past the end of the RIIO-T1 period will be built on high level assumptions that are unlikely to occur exactly as predicted. There are likely to be new requirements that emerge over the RIIO-T1 period in relation to periods post 2021. These would be analogous to the Anticipatory (ENSG) Investment in TPCR4. The impacts of these will either be covered by uncertainty mechanisms in the RIIO-T1 period or be at network companies' risk.
3	**Do you support the basis of our initial sweep assessment?**

	The basis of assessment appears reasonable and covers the main areas we would expect to be considered. The first application of this initial sweep assessment will be within RIIO-T1. As with the requirements of the well justified business plans, both network companies and Ofgem will learn a lot about the process and we welcome open discussions regarding the evolution of this initial sweep assessment through the RIIO-T1 period. As noted elsewhere in this response we encourage Ofgem to consider the first submission of the RIIO-T1 plan in July as a ‘stepping stone’ on the way to a well justified business plan submission in April 2012. This enables necessary stakeholder engagement to be undertaken past this point to enable 3rd party views to be fully reflected in final plans.
4	**What should be included in our assessment of past performance at these first reviews?**
	The assessment of past performance should incorporate the following principles: • Consistency with the principles of the TPCR4 settlement, rather than using any potential RIIO regime requirements. For example, for NGET we understand that Ofgem has concerns regarding the volumes of asset replacement undertaken in the TPCR4 period due to asset life extensions. Any assessment in this area needs to be against the principles of the TPCR4 capex allowances, and not relate to any potential incentive that could apply under the RIIO regime. By using the principles of the TPCR4 settlement in this way network companies will receive credit for performance during the TPCR4 period under the regulatory regime of the period. • There should be no use of hindsight to assess past performance. This would unduly punish reasonable decisions made in good faith using the information available at the time. This enables the assessment to be both quantitative and qualitative. With the annual regulatory reporting packs Ofgem has a tool to ensure that this can happen. The data tables, narratives and question responses, along with discussions in the related cost visits, should be used to understand the economic and commercial background of the decisions (for example the impacts of global demand on real price effects). We suggest the following items are included within this assessment: • Performance against incentive targets (TO and SO) during the period • Engagement across the industry during the period and the network’s role in facilitating change. For example, how have network companies engaged with stakeholders and how have they led and responded to changing stakeholder expectations. • Responses by the network companies to the requirements of stakeholders and customers. For example, how network companies responded to cross industry challenges in the period such as system reinforcement (Anticipatory Investment) and transmission access developments. • Qualitative assessment of the network companies’ annual regulatory reporting packs and related cost visits, although we recognise that this may be more applicable to future reviews as the RRP packs would need to be developed to adequately perform this. • Delivery of efficiency savings throughout the period and results in opex

	benchmarking exercises such as ITOMS and GTBI, which would identify efficient costs
5	**Do you have comments on the proportionate treatment process?**
	We agree with the proportionate treatment process, although retain reservations around the fast tracking process which are covered elsewhere in this response.
6	**Do you have comments on our assessment criteria?**
	We agree that all of the 15 criteria are items that should be included in a well-justified plan. As noted in our response to other questions, the methods network companies use to show these criteria within their plan and related narratives will evolve over the next few months. Whilst the criteria are sensible, there are some significant new items listed under the RIIO regime and the presentation of these in a plan is open to interpretation by network companies. We would welcome discussion with Ofgem in this area to ensure that we can meet the expectations and keep the narratives concise, proportionate and logical.
7	**Do you support the way we propose to apply fast-tracking?**
	As noted elsewhere we encourage Ofgem to consider the July 2011 submission for RIIO-T1 as a 'stepping stone' in the formulation of a well justified business plan. The April 2012 submission should be seen as the final plan because this will allow necessary and more detailed stakeholder engagement to inform the plan. We retain material concerns with the concept of fast-tracking in RIIO-T1 as we believe it is putting unnecessary time pressure on the development of well-justified business plans early on in the process. With the final RIIO strategy document only available in March and the first RIIO-T1 submission four months later, there is limited time to incorporate all requirements to cover a critical and uncertain period for the energy industry. Whilst requirements for the new regime are evolving it is difficult to see how fast tracking can be applied to this first review. A dis-application of this approach for the first review and therefore subsequent further time for enhanced stakeholder engagement and development of plans would be beneficial for consumers, Ofgem and networks alike.
8	**For RIIO-GD1, do you have views on the additional reward reflecting their relative superiority over comparators. Which of the options for implementing the reward do you prefer and why?**
	Please refer to National Grid's Gas Distribution response.
Chapter 4	
1	**Do you agree with our view that the case to develop the framework to enable third parties to compete to develop and own elements of the electricity transmission network is significant, and that we should work to develop this option as a priority? Do you foresee any areas of significant benefit or concern?**
	Two things are required to serve the interests of consumers when network investment is required:

	• Identify a good design (giving the customer the required benefits for expected costs) • Deliver selected design efficiently (to achieve the design at lowest lifetime cost) The extent to which it is in consumers' interest to separate delivery from design (and separate these from operation) will depend on circumstances. The benefits of enabling new entrants to deliver and own transmission assets that are identified in the consultation document may easily be unwound if a suboptimal design is selected (delivering the wrong thing efficiently does not help consumers). Indeed, given the importance in today's planning process of addressing the interplay between design choices and the expected delivered outcomes, especially on environmental and amenity aspects, the ability to progress any solution to benefit consumers may depend crucially on this interface. On this basis, we think there is scope for third parties to deliver services that can be functionally specified, have little scope for unwanted interactions with other systems or services, and can be the subject of operational incentives aligned with consumers' interest. However, where offered, new services may give rise to unwanted interactions or require use of limited resources such as opportunities for consents or planning permissions in environmentally constrained areas, a coordinated design by a party directly informed about delivery issues (and perhaps also operational aspects) may deliver better overall benefits.
2	**Do you consider there is a case for introducing competition for development and ownership of gas transmission assets? What form this should take? Do you foresee any significant barriers to the development of a competitive regime? When would be the appropriate time to develop this option?**
	Our delivery model for the construction of significant new gas transmission assets is to outsource, through competitive tender, both the detailed design and build phases of the scheme. This model has proven effective in finding the efficient market price for the scheme, and exploits National Grid's extensive knowledge and experience in this area to deliver maximum market leverage and therefore value for the end consumer. Our experience has shown, however, that contractors are cautious about taking a long term view of the relationship with us, due to the unpredictable and irregular nature of our load-related pipeline construction projects. It follows that if this is true of the relationship with us, it will also be true of any third party operating under the same regime. Whilst competition in the development, delivery and ownership of significant infrastructure is clearly feasible, against this backdrop of irregular investment we would question how this could deliver a more efficient and economic solution. The cost of the capital used to finance the investment will have an impact on the required rate of return, and is usually assessed against the riskiness of the investment itself. If the regulatory model for any potential third party development and ownership of transmission assets is equivalent to ours (e.g. construction and cashflow risk are treated in the same way), the required cost of capital for the scheme is unlikely to be materially affected provided the developer has an investment grade credit rating. If the regulatory model for such investments differs, consideration must be given to the level of risk being transferred to consumers. Consideration would need to be given to the planning processes currently in place. As the most significant driver by far for the required timescale to deliver new infrastructure, care must be taken in the development of this option to ensure it

	does not detrimentally affect the timely delivery of required assets. We would also need to consider wider implications resulting from such an option of primary legislation, such as interactions with our Safety Case and the various safety regulations under which we operate. A full assessment would be required during the development of this option to ensure we remain legally compliant. Finally, a number of issues would need careful consideration such as funding arrangements for the party charged with the responsibility of maintaining and operating the new infrastructure, liabilities should the development be late and accountability for the cost of constraints should there be a failure of the new assets.
3	**In light of the role competition already plays in gas distribution do you feel there is a case for making further provisions to enable new entrants to develop and own parts of the network? If so, what form do you think these provisions should take?**
	Not applicable to Transmission – please refer to National Grid's Gas Distribution response.
Chapter 5	
1	**Should the scope of the innovation stimulus be confined to projects which help deliver a low carbon future, or should the scope be wider to include long-term network sustainability? Should there be a different scope to the innovation stimulus that applies to electricity and to gas?**
	We believe it should be expanded to include long term network sustainability, however we need to be careful with the definition of 'sustainability'. The example used in option 2, section 5.10 is not one we think fits the definition of sustainability. The example is a worthwhile innovation challenge, however one that should be included in core innovation within business plans. Before the stimulus fund begins, Ofgem and stakeholders, via one of the planned workshops, should clearly define 'sustainability' in the context of networks. We believe it is imperative for Ofgem and stakeholders to more clearly describe the low carbon future and the targets being set for the networks sector to achieve. This will be important for both managing the fund and for describing to customers. Gas and electricity will have different challenges, however the core goal for each of delivering a safe, secure, affordable and sustainable network remains the same. We do not believe a separate scope is required for each; our ambition for decarbonised and sustainable networks is valid for both.
2	**Do you agree that the level of funding available under the innovation stimulus for each of electricity transmission and gas distribution and transmission should be within the ranges identified? Are there further arguments for different funding levels which we have not considered?**
	The ranges Ofgem have outlined are on the low side of what we believe will be required to deliver a low carbon future. We also assume that offshore transmission is out of scope, or the size of the innovation fund would need to be significantly higher if it were included. The scale of the change required is significant. The size of the fund should be linked to the ambition we collectively have in delivering the low carbon future. While a limitless fund would not guarantee success, we must pursue all avenues in developing solutions to meet this complex problem and work collaboratively as an

	industry across all interested areas in order to optimise all available funding for innovation. We therefore support collaborative working to ensure funding is co-ordinated across sectors and fuels to ensure best use is made of the funds available. Expressed as a percentage of revenues, which is one of the leading global indexes used for assessing funding, the level proposed is less than half the global average across all industries. We therefore recommend that the level of funding is set higher and closely monitored for benefits delivered. It will be easier to reduce spend than to increase the size of the fund if we discover that it is insufficient. Having a larger fund agreed at the outset does not mean it all has to be spent. As per our open letter of November 2010, we estimate that an eight year fund of £800million to £1.2billion is required (Electricity Transmission £240m-£400m, Gas Transmission and Distribution £560m-£800m). Ofgem, via its expert panel, should be able to tightly control spend against targets and progress to ensure value for money delivery for customers. There is scope for innovation in gas networks in order to manage our response to the new challenges in meeting customers' changing requirements for flexibility of the network and facilitating changing gas mixtures. Transmission and distribution elements within gas and electricity funds should be kept separate. All four areas face significant and different challenges and pooling Transmission and Distribution funds may lead to projects competing against each other which may not lead to an optimum portfolio of projects. There may be an option of a notional split between Transmission and Distribution within the same fund to maintain a degree of separation. We note Ofgem's comments that the electricity transmission system is already relatively smart. We agree that it is in comparison to distribution networks, however there is still considerable scope to apply 'smart' technologies in order to meet the low carbon future vision. Transmission projects should not need to compete against distribution projects, but should complement them. By their nature, Transmission innovation projects tend to be much larger and longer to demonstrate, so while fewer in number compared to distribution projects, their costs tend to be higher. Award of projects is likely to reflect ability to roll out benefits to other networks as well as on customer benefit. Care needs to be taken with the criteria so as not to make it difficult for Gas Transmission, for example, to compete because there are no competitor networks to which the results can be rolled out.
3	**How should network companies be required to meet the costs of the innovation stimulus? Should this be through fast cash, slow cash or the standard expenditure capitalisation ratio?**
	In terms of funding profile we would favour option 2 as set out in section 5.25. We acknowledge the downside of this approach put forward by Ofgem and we believe these are very valid concerns. However, the ISF is likely to begin in 2013, leaving seven years before 2020 and the climate change targets we are looking to support. Given the scale of the challenge before the industry, we should accelerate all options to give us the maximum chance of success in collectively curbing CO_2 emissions by the target dates. The governance arrangement should be developed robustly enough to allow

	Ofgem to consider and approve projects it feels necessary to deliver the targets set, without feeling constrained by arbitrary annual maximum figures. The ISF should provide 90% of the funding for projects, similar to the approach adopted for the LCNF. An 80% maximum places more risk on companies sponsoring projects that they not see a return from their 20% contribution. Since the aim of the scheme is to avoid that scenario, it seems practicable to maintain the level as per that for the LCNF. Requiring a 20% contribution could dis-incentivise some companies from coming forward with potential projects. We agree that fast money would be appropriate; this is simpler to administer, supports cash flow, and is consistent with the Low Carbon Network Fund.
4	**Do you agree that we should provide a <u>limited</u> innovation allowance directly to each company? If so, do you have views on the form and scope and of this allowance, and on which mechanism would best incentivise efficient investment in innovation?**
	Yes we strongly support the inclusion of an innovation allowance directly within each company. We favour option 1 as set out in section 5.35. We are pleased Ofgem is minded to increase the level to 1% of revenues. It should be left to companies to manage internally, producing an annual report which describes the innovation undertaken and the benefits obtained. As part of submitting our business plans for RIIO-T1 we will provide overviews of the main innovation areas we plan to pursue.
5	**Do you agree that there should be a revenue adjustment mechanism to encourage innovation roll-out within the price control period? If so, do you agree with our views on the criteria for such an adjustment and how frequently should we allow companies to apply for this adjustment?**
	Yes, an adjustment mechanism is important but needs to allow flexibility and not be timebound. We would favour option 1 as set out in section 5.42.
Chapter 6	
1	**Do you agree with our proposed approach to the implementation of the efficiency incentive rate? Do you have views on the intergenerational impact?**
	We support the rationale of adjusting revenues as soon as practicably possible without the added complication of forecasts. The method outlined in the document seems reasonable and in line with the totex approach. By adopting this approach any savings (or otherwise) should be fairly split between current and future customers as long as the initial split (i.e. % totex added to RAV) is reasonable. The exact process of adjusting income (i.e. restating RAV vs. income adjustment with changes to RAV logged up) needs further thought. Our preference is that this process would be incorporated into the annual RRP submission and review. Through this process actual spend can be verified and any necessary and efficient tests applied by Ofgem on a timely basis. We favour an income adjustment for the incentive rather than changing our core allowed income. This will give better visibility on exactly what adjustments are being applied. As per paragraph 6.14 these changes can then be totted up and

	RAVs adjusted at the end of the control.
2	**Do you agree with our proposed range for the efficiency incentive rate?**
	The proposed range for the efficiency incentive rate includes the effective totex incentive rate provided by the current controls and therefore appears appropriate.
3	**Do you agree with our proposed approach to the calibration of the IQI?**
	There are three key factors which need careful consideration to ensure the IQI is fairly calibrated. The first is ensuring that Ofgem's forecast and cost assessment is reasonable. The proposals that are currently being developed for cost assessment are at a very early stage in development. There are some techniques which are completely new and it is crucial that these are used appropriately in setting an initial forecast. The second key factor is which version of the companies' business plans is used for comparison. It is our belief that to use the operators first forecast vs Ofgem's last is not appropriate. There are three reasons for this conclusion: • Stakeholder engagement for RIIO-T1 will continue beyond July, 2011. Use of the last plan will therefore allow stakeholder views to be more comprehensively captured by the RIIO framework • Companies' plans will be influenced by Ofgem's efficiency measures. These measures of cost efficiency are unlikely to be at an advanced enough stage to be properly incorporated into our business plans for the July 2011 submission (Ofgem is still developing the techniques at present). Using our last plan will allow us to build the results of the relative efficiency analysis into our plans in a targeted and measured way to deliver most benefit to the consumer. • To use a company's first plan leaves no incentive on our subsequent submissions. Using our final plan leaves the power of incentive intact for any revisions to our base plan. It seems unreasonable to judge operators by their first forecast and instead operators' last forecast should be compared against Ofgem's last forecast. In many ways, it may be more appropriate to consider the July 2011 submission as a stepping stone to the submission of a fully developed well justified business plan in March 2012. The third factor is the level of additional revenue that is awarded through the mechanism. Previous controls have awarded additional revenues for being close to Ofgem's forecast to a penal approach of taking revenues away unless company forecast is equal to or better than Ofgem's forecast. This changes the nature of the incentive from one which rewards accuracy to penalise inaccuracy. A symmetrical incentive would be more consistent with the RIIO framework. We note that Ofgem are proposing that, unlike the approach for DPCR5, real price effects (RPEs) should form part of the IQI matrix together with other costs. Whilst we appreciate that the aim is to ensure RPE forecasts are robust, we are not convinced that this is practical given the inherent uncertainty. As set out elsewhere in this response, our preference would be to cover this with an uncertainty mechanism. Finally a more general comment on Paragraph 6.32 regarding exclusions. This point requires further clarification. Exclusions must be set out clearly in advance and be definitive, we would also encourage them to be minimised wherever

	possible.
4	**Do you agree with our proposals for the application of the RIIO approach to efficiency incentives to the areas of gas transmission expenditure that are currently covered by the suite of separate incentive schemes set at TPCR4?**
	We broadly agree with the proposals for the application of the RIIO approach and that this will simplify the arrangements and remove the potential to distort decisions between operational and investment actions.
5	**Specifically, do you agree with our proposals to apply the same efficiency incentive rate, and to have no caps and collars? Do you have any views on the potential downsides and risks to consumers?**
	We agree with the proposals to apply the same efficiency incentive rate. The removal of the caps and collars is possible, although the potential impact on cashflows would have to be reflected in the financeability assessment. We are confused by the section describing the managing of risks under a single efficiency incentive rate. This suggests that the caps and collars could be removed and replaced with an uncertainty mechanism with thresholds. Given that the uncertainty mechanism described would appear to act exactly like the current caps and collars, we do not understand what advantages that this would bring, particularly since the original objectives include the simplification of the arrangements. We would welcome the opportunity to develop this area further with Ofgem and our stakeholders.
6	**Do you have views on the scope for alignment between the TO and SO incentive schemes, including greater alignment than we have proposed?**
	Whilst we are always seeking opportunities to further align TO and SO incentives, we do not believe that there is any practical scope for further alignment at this time.

Uncertainty mechanisms

Chapter 2	
1	**Are there any additional criteria that we should take into account to guide the appropriate use of uncertainty mechanisms?**
	We broadly agree with the principles guiding the use of uncertainty mechanisms set out in the consultation document. For the potential justifications for uncertainty mechanisms set out in Table 2.1, we note that the potential impact on cost of capital must be viewed in light of the other changes associated with the RIIO framework (e.g. 8 year control period, etc.).
2	**Do you agree with the information requirements that we set out to support the justification of additional uncertainty mechanisms? If not, what changes should we make to these requirements?**
	We broadly agree with the information requirements listed in Table 2.2. It may also be worth considering any interactions between proposed uncertainty mechanisms. This section also notes that under the RIIO framework, network companies need to set out how they intend to manage risk through the price control period. It would be helpful to better understand how Ofgem intends to assess this overall risk strategy and we look forward to further clarification in the March documents.
Chapter 3	
1	**Do you think there should be a change to a 12-month average approach to RPI indexation of allowed revenues? If there were a change to a 12-month average approach, would there need to be any transitional adjustments?**
	We agree that it makes sense to align the RPI period used across the various sectors and see no reason in principle not to move to a 12 month average approach. The most appropriate option would be to use the January to December average. Provided the current notice periods for setting charges are not changed, actual RPI data should be available, avoiding the need to use estimated data for the setting of final charges. If April to March was used instead, estimated RPI data would need to be used increasing the risk of under and over recoveries. Under such circumstances we would recommend a widening of the band before penal interest rates applied to deviations, and that a process be agreed with the industry for determining the estimated RPI data. Using January to December therefore seems the optimal approach as it delivers the advantages of a 12 month reference period without the disadvantages of relying on estimated data. We note that the offshore transmission regime uses the January to December period.
2	**Do you have any views on the design of the reopener for the introduction of Traffic Management Act permitting schemes? In particular, is the timing of the reopener window appropriate and what approach should we adopt to set the materiality threshold before it can be triggered? Do you agree with our proposal that the reopener would only apply in gas distribution?**

	During the RIIO-T1 period, NGET is expecting to complete significant cable replacement works in Sheffield and Birmingham and therefore we will be exposed to the costs associated with any permitting schemes in these areas. We will therefore propose the inclusion of a re-opener similar to that proposed for RIIO-GD1 as part of our well justified business plan.
3	**Do you have any views on the design of the mechanism for changes in the requirements required by the Centre for the Protection of National Infrastructure? As above, is the timing of the reopener window appropriate and what approach should we adopt to set the materiality threshold before it can be triggered?**
	Having an uncertainty mechanism for unforeseen increases in current requirements from the CPNI in the RIIO-T1 period is sensible, although we have reservations regarding the design proposed by Ofgem, specifically in relation to the inflexibility of the reopener period. With significant work already undertaken during TPCR4 in this area any new requirements should relate to two areas: • New, more stringent security standards requiring investment above that included in the scope of TPCR4 work • Changes to flow patterns on the network increasing the criticality of certain sites requiring further investment under current security standards The design of the uncertainty mechanism needs to cover the risk involved in these two areas. We agree with the proposal for the materiality threshold being based on allowed expenditure, rather than as a percentage of revenue. This represents a better indication for the impacts of such requirements. On the other hand only having a potential reopener for this expenditure at the halfway review could cause funding difficulties. National Grid's experiences in the TPCR4 period suggest this is the case. In the TPCR4 settlement a logging up mechanism for such expenditure was proposed but during the period it quickly became clear that the scale of necessary investment required a change to this mechanism. The lessons from this should be considered. We are surprised by Ofgem's statements in the consultation document which suggest there have been no requirements for such expenditure to date, and funding requirements have not been agreed. In Transmission we have been working with security agencies to deliver necessary reinforcements to the security surrounding key sites during the TPCR4 period. We have also had a number of written correspondences with Ofgem regarding the funding mechanisms to ensure appropriate recovery of the costs of these activities on an ex post basis, one year after projects deliver. This correspondence included draft licence terms which are due to be implemented. We suggest that this mechanism is continued into the RIIO-T1 period because a) it should already be within the license and would need no adjustment, b) already incorporates the lessons from the TPCR4 period.
4	**Are there any additional mechanisms that we should be considering? If so, how should these be designed?**
	In developing our well justified business plan, we will endeavour to build a better understanding of the uncertainties associated with the RIIO-T1 period and the

	justification for additional uncertainty mechanisms. As highlighted in Chapter 2 of the consultation document, we are currently considering the justification for and design of additional uncertainty mechanisms to deal with, in particular, Real Price Effects, the interactions between outturn RPI and the RPI assumed by Ofgem to calculate tax allowances, Pension Protection Fund levies and the requirements for undergrounding in electricity transmission.
5	**Do you agree with our proposal to leave the disapplication arrangements unchanged?**
	We do not see any reason to make changes to the disapplication arrangements.
6	**Do you have any views on the other mechanisms discussed in this chapter?**
	We agree that pass through of Ofgem licence fees and business rates appears to provide an appropriate treatment. Our views on cost of debt indexation, pensions deficit repair mechanism and tax trigger are contained in our response to the finance document.
Chapter 4	
1	**Do you have any views on our proposed approach to managing uncertainty around connections volumes?**
	Please refer to National Grid's Gas Distribution response.
2	**Do you agree with our proposal to remove the loss of meter work revenue driver? If not, why do you think retaining the mechanism is in the consumer interest?**
	Please refer to National Grid's Gas Distribution response.
3	**Are there any additional mechanisms that we should be considering? If so, how should these be designed?**
	Please refer to National Grid's Gas Distribution response.
4	**Do you agree with our proposal to leave the disapplication arrangements unchanged?**
	Please refer to National Grid's Gas Distribution response.
5	**Do you have any views on the other mechanisms discussed in this chapter?**
	Please refer to National Grid's Gas Distribution response.
Chapter 5	
1	**Do you agree that it is appropriate to continue to use an uncertainty mechanism for delivering entry and exit capacity in gas transmission, and do you agree that revenue drivers are the most appropriate uncertainty mechanism?**

	We agree that it is appropriate to continue using an incremental entry and exit capacity uncertainty mechanism, and that the revenue drivers are the most suitable form of mechanism. We would like to consider, however, the balance of risk around the mechanism in its current form. The existing mechanism is a blunt tool which, for smaller incremental capacity projects, works well enough but for larger projects may be too simplistic. Currently, following full financial commitment (in the form of an auction signal for entry capacity, and user commitment for exit capacity), a revenue driver for the full investment amount is triggered. We would like to investigate whether a staged approach would be more appropriate for more significant projects, given the inherent uncertainties and elongated timescales relating to the planning process. Such a move would need to consider suitable triggers for each stage, but has the potential to introduce protection for consumers against forecasting risk. Should a multi-staged approach be agreed, we would also like to take the opportunity to align the obligated timescales for the two processes for the gas transmission system, the customer for whom the incremental capacity is to be made available, and in the case of CCGTs the lead times for connection work to the electricity transmission system. Currently incremental entry and exit capacity is obligated 42 and 38 months after receipt of a signal, which may or may not align with significant milestones for each of these parties and does not align with current planning processes.
2	**If you think that a different mechanism could be more suitable, do you have any views on how such a mechanism could operate?**
	As described in our response to the RIIO-T1 outputs and incentives consultation, we believe that customers' network flexibility requirements have the potential to become a significant driver of investment during RIIO-T1. Uncertainty mechanisms, similar to those set out for Electricity Transmission wider works, may provide the most appropriate means of funding these investments. We outline some further thoughts on uncertainty mechanisms for gas flexibility investment in response to question 5 below.
3	**Do you agree that our proposals will properly align the mechanism with the RIIO framework?**
	We agree that the proposal to apply an efficiency incentive rate to the revenue drivers for entry and exit incremental capacity does help align the incentives with the RIIO framework. Alignment of exposure between the constraints and the construction costs is a necessary move to ensuring optimal decisions can be taken. Some unit cost allowances for revenue drivers are agreed for potential connections in a timely manner which allows for appropriate reflection of the capability of the NTS at that time (and therefore of the necessary investment to meet the required incremental capacity), whereas others are set well in advance and therefore risk being outdated. This represents a risk to both consumers and ourselves as the revenue driver could differ materially from the actual investment required, and consideration should be given to refreshing the unit cost allowances for more material levels of investment in advance of potential incremental capacity signals. Whilst this approach increases the resource requirement to perform more frequent updates of the unit cost allowances, the benefits in terms of more accurate revenue drivers would far outweigh this additional cost. A sharing of the risk of such

	material differences would seem appropriate. On a related point, material levels of incremental capacity should, when triggered, be reflected in the capacity buy-back regime as the risk profile for constraints will be impacted, both through the changing operational dynamics of the network and through the act of physically connecting (i.e. system outage requirements). Whilst this represents a degree of volatility in this constraint management incentive, it is necessary to ensure balance is maintained between constraint and construction cost decisions and therefore that an appropriate balance of risk is maintained.
4	**Do you have any views on changes to the operation of revenue drivers if there are delays on the user side?**
	In our response to Chapter 5, Question 2 (above), we discuss the potential for a staged revenue driver. Such a mechanism would help to reflect delays on the user side until the start of the build phase of any necessary infrastructure investment. In the situation where a user's project is delayed, the next stage of the revenue driver would not be triggered which in turn would defer the construction activities. There are additional costs in mothballing a project and standing down or remobilising resources, which should be reflected in the mechanism if such delays were to occur.
5	**Do you have any views on the process that would be used to set the value of revenue drivers at specific entry or exit points?**
	Historically the process to set revenue drivers at specific entry and exit points has used assumptions relating to the flow patterns anticipated at that point, and on their interaction with the wider network. When multiple connection requests are received for the same geographical area and for similar delivery dates, consideration needs to be given to delivering the optimal solution for all parties, rather than developing individual solutions (either contractual or investment) for each connection sequentially. Changes to the behaviour of the entry or exit point in question can lead to different interactions with the wider network to those anticipated at the time of setting the revenue driver. This can be categorised into three distinct areas: 1. Changes to supply patterns as a result of UKCS decline, greater penetration of LNG supplies, more fast-cycle storage and greater levels of intercontinental connections 2. Greater levels of CCGT capacity requiring shorter lead times and faster ramp rates to allow them to respond to electricity market needs 3. Changes to either the pressures and/or within-day flexibility required by the Distribution Networks to allow them to operate. For new incremental entry and exit capacity, the current process to set the value of revenue drivers needs to be expanded to include changes to network use from existing users and other new users requesting connections in similar timeframes, in response to: • requests for higher Assured Pressures at offtake and/or more flexibility from the Distribution Networks • requests for shorter lead times and faster ramp rates from CCGTs • our forecast and actual changes to flow patterns. The changes to required lead times and ramp rates, and DN pressures/flexibility,

	should be manageable with changes to arrangements and processes based on user driven signals and commitment. Changes to supply patterns pose challenges as they span both existing and new connections, and there are currently no mechanisms to gain user signals ahead of need. Consideration needs to be given to development of output measures which can capture the changing behaviour of existing capacity beyond that assumed credible when the original revenue driver was agreed. We welcome the opportunity to work with Ofgem and our other stakeholders to address this issue.
Chapter 6	
1	**Do you think that an uncertainty mechanism for electricity transmission connections expenditure is likely to be in consumers' interests?**
	During RIIO-T1, the electricity generation sector is expected to experience significant changes associated with the decarbonisation of the electricity generation mix and the replacement of aging power stations. The electricity transmission connection expenditure associated with these changes will be dependent on the siting and timing decisions made by individual generators and therefore is likely to remain very uncertain during the RIIO-T1 review. The TPCR4 review period was arguably more stable for the generation sector and yet the changes to generators' transmission connection requirements during this period have been substantial, with considerably more generation being connected than in National Grid's TPCR4 baseline allowance. The scale of cost and extent of uncertainty associated with this category of expenditure therefore means that an uncertainty mechanism is likely to be in consumers' interests. Without such a mechanism, consumers would be exposed to significant forecast uncertainty.
2	**Do you have any views on future connections projects (number of projects, costs, etc.), and the uncertainty around these numbers?**
	In order to better understand the uncertainty associated with future connections projects, National Grid utilises a scenario approach. The Offshore Development Information Statement [18] contains details of four scenarios: gone green, slow progress, accelerated growth and sustainable growth. The main difference between this selection of scenarios is the type of generation used to meet demand and the timing and scale of future generation projects. Whilst the costs of particular transmission connection projects may be known, it is important that the interaction between multiple transmission connection projects to the same part of the transmission network is taken into account. This requires detailed analysis and we intend to complete this as part of the development of our well justified business plan.
3	**Do you agree that volume drivers are the preferred option, and do you have any views on how they should be designed?**
	Volume drivers have the advantage of removing forecast uncertainty whilst maintaining a forward-looking incentive on networks to deliver the volume of connections requested by customers at an efficient cost. They should therefore be

[18] http://www.nationalgrid.com/uk/Electricity/ODIS/CurrentStatement/

	the preferred option. The consultation document highlights the interaction in DPCR5 between the type of volume driver and the boundary between assets funded from the price control and those funded from direct charges. Clearly, it will be important to be cognisant of the progress of Project TransmiT during the design of this uncertainty mechanism. During the development of our well justified business plan, we will explore the cost drivers for transmission connection projects. We will propose a mechanism which strikes an appropriate balance between accuracy and complexity. In terms of accuracy, it is important that both the costs and lead-times of the projects covered by the volume driver are reasonably consistent. The use of alternative arrangements for qualifying high-cost (and therefore long lead-time) connections projects described below may be important in this regard.
4	**Are any other uncertainty mechanisms needed for connections expenditure? If so, how should these be designed?**
	One of the costs associated with connections is the cost of providing flexibility to generation developers to delay the connection date in line with their project development programme. This can involve significant reworking of the capital and outage plans, including the advancement or deferment of other capital schemes, to move back towards optimality. As part of the development of a well-justified business plan, we will seek to identify these costs and will consider the appropriateness of an uncertainty mechanism, although this may be better handled as a modification to a volume driver for transmission connections expenditure.
5	**Do you have any views on the option of setting upfront revenue allowances, during the price control period, for qualifying high-cost connections projects?**
	Broadly, ‘enabling’ works are those required to connect the generator to the main transmission system whereas ‘wider’ works are those required to achieve an economic and efficient level of main transmission system boundary capacity. The distinction between ‘enabling’ and ’wider’ works is therefore not directly related to the scale of the associated projects and expenditure, and there may be transmission connections which involve significant ‘enabling’ works. For this reason, an arrangement which would allow significant connection projects to be treated in a manner consistent with wider reinforcements appears to be appropriate.
6	**Do you have any views on the uncertainty mechanisms that we have proposed for wider reinforcement works?**
	We welcome the proposed uncertainty mechanisms for wider reinforcement works set out in the consultation document, which represent a pragmatic step forward. In considering potential mechanisms, it is necessary to achieve the appropriate balance between options which involve significant administrative burden and risks of micro-management and options which involve levels of risk which are too high for networks and/or Ofgem to contemplate. Option (a): trigger mechanisms calibrated at the price control review would appear to bring benefit to consumers. Administrative burden and risks of micro-management are minimised because the trigger is specified ex ante and applied mechanistically. The network’s incentive to innovate remains and the network’s overall resource and cash-flow optimisation is not contingent on Ofgem decision-

	making. Option (b): within period determinations to approve further deliverables also has the potential to bring benefit to consumers. We note that the administrative burden and risks of micro-management are higher than for the other options and therefore we would initially expect this option to be used in more exceptional circumstances. We also note the additional obligations associated with scheme development and an up-to-date network development plan and welcome the acknowledgment of the associated costs. Option (c): network planning policy and volume driver agreed upfront appears to provide the most potential to bring benefit to consumers. This is because it offers the minimum administrative burden and risk of micro-management and therefore the maximum discretion for networks. This provides the maximum opportunity for networks to innovate and optimise overall resources and cash-flow. The key to the success of this option is clearly the network planning policy, and the way in which some of the potential concerns noted with option (d) (e.g. potential time lag between build and utilisation, success of generation and demand forecasts) are addressed. We note the potential concerns associated with option (d): company discretion subject to utilisation incentive scheme and in particular those associated with an unacceptable level of risk and consequential cost for consumers. We disagree that the financial incentive is simply a way to improve generation and demand forecasts, since there is considerable scope for innovation in the design of the optimal network reinforcements. We intend to explore incentive options which could provide mitigation against the risks identified whilst providing further incentives to innovate and reducing administrative burden as part of the development of our well justified business plan.
7	**Do you have any views on the treatment of Inter-TSO costs?**
	The ITC scheme is now mandatory under the Third Energy package and the methodology and associated variables are set by the European Commission and therefore we have no direct control over the associated costs. The European Commission seek views from ENTSO-E in setting the methodology and associated variables for the ITC scheme. National Grid is committed to ongoing engagement with other ENTSO-E members to develop the scheme to be as cost reflective as possible. On this basis, we consider the pass-through of Inter-TSO compensation costs to be appropriate.
Chapter 7	
1	**Do you agree with the scope of the mid-period review? If not, what changes to the scope are needed?**
	We agree with the limited scope proposed for the mid-period review, which should prevent the price control period collapsing to four years. Ultimately, this means that the success of the eight-year price control is reliant on the development of the appropriate uncertainty mechanisms. In addition to changes in Government policy, the main areas where we anticipate

	the potential need to add additional outputs in order to better meet consumer needs are environmental emissions (where an improved understanding of environmental impact may lead to a need to add outputs for other emissions) and customer satisfaction (where changes may be required to address customer needs).
2	**Do you agree with the indicative process and timetable? If not, how could the process and timetable be improved?**
	We broadly agree with the proposed indicative process and timetable for the mid-period review. In order to reflect any changes in charges from April 2017, an Ofgem decision would be needed by mid-January 2017 at the latest. It is important that the information contained in this decision is in a format which can be readily incorporated into charges as there will be no further time available to address any uncertainty.
3	**Do you have views on when we should make licence changes as a result of any actions taken at the mid-period review? If a threshold to make a licence change is seen as appropriate, what should this be?**
	Given the Government Response to DECC's consultation on Third Package Implementation, and its confirmation that licence modification will be appealable to the Competition Commission, we strongly prefer option 1 on the grounds that: • It gives clarity and certainty of process in terms of making changes; and • It gives licensees the right to appeal if it disagrees.

Financial issues

Chapter 2	
Please note that the following is a combined response covering National Grid's views on RIIO-T1 and RIIO-GD1.	
1	**Do you agree with our proposed economic asset lives for gas and electricity transmission and gas distribution?**
	Principle of moving to economic asset lives The RAV asset lives chosen in previous price controls were selected on the basis of a number of considerations. Recurring themes include the impact on the financial position of the companies and the impact on longer term prices. These considerations were considered important for the consumer as well as the companies. By way of example, when commenting on the advantages of the tilting depreciation approach adopted for the RECs during DPCR3 Ofgem stated "it is a means of increasing certainty with respect to the financial position of the distribution businesses and the path of prices in the longer term. The benefits of this will be felt by both customers and companies."[19] As recently as January 2010, in their RPI-X@20 consultation[20], Ofgem listed a range of factors that should be considered is setting asset lives and the approach to depreciation. These included: • Transparency and predictability • Balancing the interests of current and future consumers • Price signals (and cost reflectivity) - how important is it that consumers and users face appropriate price signals • Incentives (i.e. impact on incentives faced by the networks) • Reliance on cash flow ratios (and whether this is necessary and appropriate) There is a long history of Ofgem considering a range of issues such as these. These issues are equally relevant today and it is not clear why Ofgem now believe it is appropriate to determine asset lives with a sole focus on economic asset lives. Ofgem's decision to adopt an economic asset life appears to be based on the objective of balancing the interests of current and future consumers. National Grid has previously questioned whether or not a <u>retrospectively applied change</u> in asset lives would improve intergenerational fairness at all in electricity. As figure 2.10 of the Financial Issues annex demonstrates, an increase in asset lives increases the long term costs that future consumers pay to the benefit of customers in the short term. It is difficult to reconcile the short term subsidy that would be provided to current consumers at the expense of future consumers with Ofgem's objective to balance more fairly the needs of current <u>and future consumers</u>. Current consumers continue to benefit from artificially low charges caused by the discount between net replacement cost and RAV incorporated into the initial RAV valuation of pre-privatisation assets. This discount has been retained for the advantage of both

[19] DPCR3 Final Proposals (1999), paragraph 5.35
[20] "Regulating Energy Networks for the Future: RPI-X@20 Emerging Thinking – Embedding Financeability in a New Framework", Ofgem, January 2010, paragraphs 4.6 to 4.22

	current and future customers by the maintenance of the current level of depreciation. The impact of an increase in lives would be to utilise the whole of this discount to artificially depress current charges and further distort economic prices which could have unforeseen consequences. It appears to be widely accepted that energy costs will rise in the future given the increased demands for declining fossil fuel resources and the need to decarbonise the economy, with the resultant impact on electricity generation costs. Current customers are benefitting from relatively cheap energy and minimal restrictions on emissions which will not be available to future customers. This is an intergenerational energy issue that would be exacerbated by any extension of asset lives. Investors are asking ‘why do asset lives need to be extended?’ and it is clear that Ofgem has not adequately demonstrated or communicated this need. The extension of asset lives is a key concern to investors that is undermining their confidence to invest in the sector. Ofgem must demonstrate how their proposals help to solve intergenerational energy price inequality and make this analysis available for critique before implementing any changes. Without this supporting evidence, regulatory risk, in this case the perceived risk of the regulator making unwelcome and unnecessary changes to the regime, will be significantly increased causing an increase in the return required to attract equity. **Replacement Expenditure (repex)** The Final Proposals in September 2001 for the Transco 2002 Price Control[21] included the following words in the summary “The renewal programme is primarily concerned with present safety requirements rather than increasing the network’s capacity or functionality for the benefit of future consumers, suggesting these costs should be expensed and met within the price control period. Nevertheless there will be some advantages to consumers in the future as replacement spending will be lower and newer assets tend to require less repair and maintenance. To deal with these tensions, ensure that Transco is able to finance its activities and ensure that price reductions are sustainable beyond the next price control period, 50 per cent of replacement spending over the next price control period will be expensed in the year that it is incurred and 50 per cent will be treated as capital and added to the regulatory asset base.” Paragraph 6.8 of the same document stated that financeability was a key consideration in deciding the proportions to be expensed and capitalised and paragraph 6.9 stated that capitalising 100% “would put significant strain on Transco’s key financial ratios and jeopardise its ability to retain an investment grade credit rating.” The issue was then reviewed in the first Gas Distribution Price Control Review in 2007, and Ofgem confirmed that they considered the 50/50 split to be appropriate[22]. It is interesting that Ofgem acknowledged that the primary purpose of the repex programme is present safety requirements for current consumers. All of these points above remain valid today and we see no justification for placing a greater proportion of the cost burden on future consumers. **Technical Lives** The technical life analysis is based on the life of installed assets. This ignores the significant changes in the assets planned to be installed or changes in the usage of assets. In many cases assets are being replaced by higher technology equipment

[21] “Review of Transco’s Price Control from 2002 Final proposals”, Ofgem, September 2001, page 4
[22] “Gas Distribution Price Control Review Final Proposals”, Ofgem, December 2007, paragraph 9.30; and “Gas Distribution Price Control Review Updated Proposals”, Ofgem, September 2007, paragraphs 9.44 to 9.46.

that has a shorter asset life. Also, assets such as circuit breakers that have traditionally been used for faults only are now being used to manage the system such that National Grid has now introduced a new category of high duty circuit breakers which have a shorter asset life.

Contrary to the comments in the Financial Issues annex 2.11, we believe this expenditure will be material as we progress through the price control period.

Economic Lives

We have significant concerns with the choice of economic lives. With regard to the lives chosen we believe there are shortcomings that have been adopted in the analysis undertaken by CEPA which have not been corrected in Ofgem's proposals.

An analysis is provided in figure 2.4 of the Financial Issues annex of the uncertainties that have been considered. Numerous other factors could also be relevant such as increasing legislative health and safety requirements for example, or an increase in the number of shorter life generation assets connected to the network. A significant change in the mix of generation assets is expected in the next couple of decades, including the introduction of more plant with potentially shorter lives such as wind farms. While the assets connecting them will typically have technical lives consistent with other assets, those assets are unlikely to have the same economic life because the connected asset will have a shorter life. This economic factor has been completely overlooked in the results presented such that future consumers are likely to find themselves paying for the connection assets of one or two generations of plant that have long since ceased to provide economic benefit.

The asset life decision needs to consider the impact of depreciation charges on consumer bills and the risk of asset stranding, which, itself, would contribute to an increase in the required rate of return and higher consumer bills.

We note that CEPA believe that under the 'Green Transition' scenario gas peak demand could fall to 70% of today's level, but annual demand would drop to 30%[23]. Within these figures it is generally accepted that there will be greater resilience in demand for gas transmission than distribution in the future, provided cost effective CCS technology can be developed, so the impact on gas distribution will be even more pronounced. The price paid by consumers will be a function of average demand, not the peak requirement during a period of time and so the asset life decision should be informed by annual demand projections. The asset life and depreciation choices need to ensure that, after considering the cost of future investments, the depreciation charges recovered in the future are sufficiently low that they can be covered by the smaller consumer base. If the future costs of the network are too high, gas may become uneconomic, accelerating the decline of gas utilisation.

The Project Discovery scenarios reviewed by CEPA ran to 2025. CEPA have extrapolated them to 2050 for the purposes of their analysis. The Redpoint 'Gas Future Scenarios Project – Final Report', published in October 2010, also considered four scenarios out to 2050. In the 'Electrical Revolution' scenario, the use of gas for both transmission and distribution is significantly reduced over a 30 to 40 year period with the transmission and distribution networks fully decommissioned by 2050. In this context, a 45 year asset life is too high. Indeed, in that scenario, average gas demand is less than 20% of the current levels as early as 2040.

For gas assets, the decision to retain 45 years as the asset life is based on a flawed argument. As highlighted in paragraph 2.26 "There is significant uncertainty around the future use of the gas network with annual load and future peak demand likely to

[23] "The Economic Lives of Energy network Assets: A report for Ofgem", CEPA, December 2010, Figures 4.4. and 4.5

	be no higher than currently. In some scenarios, gas usage could be much lower. The future of the gas network depends upon the successful development of a number of technologies including CCS and high use of bio-methane." The annex then goes on to conclude that "Our view is that it would be premature to reduce asset lives given that there are scenarios, where gas will remain an important element of the energy market". As already mentioned, if average demand is falling, the network costs to be recovered will need to fall. If this does not happen assets will be stranded. If there are credible scenarios where gas demand will be significantly lower the asset lives should be reduced to prevent such stranding. The logical argument should be that faced with uncertainty lives should be reduced not, as appears to be the case in the proposals, to postpone a decision to reduce asset lives until there is certainty that the assets will not be required. The approach currently adopted postpones the decision to reduce asset lives until it is too late, significantly increasing stranding risk. Adopting a front loaded depreciation profile is an additional and effective way of mitigating these risks but to the extent that investors perceive the risks of stranding to increase, the allowed return will have to be increased. **Other Regulatory precedents** We note in figure 2.7 Ofgem's use of other regulatory precedents for extending asset lives, in particular their references to electricity distribution and transmission in the Republic of Ireland, and UK water. We do not consider these precedents to be relevant. The electricity networks in the Republic of Ireland are owned and operated by a state owned company and as such are shielded from the capital market pressures that apply to privately owned regulated networks. The same can be said of water in Scotland. In England and Wales water, in spite of the potentially long (Ofgem refer to 80 to 250 years) lives of below ground infrastructure assets, these asset lives are not used in calculating depreciation allowances as an element of allowed regulated revenues. Instead, the allowance is based on average investment in these assets over the recent past and future years, an approach which has been used consistently in successive reviews. Thus, Ofgem's own quoted precedent does not support the increase in asset lives which is being proposed in electricity transmission and distribution.
2	**Do you agree with our proposals for the depreciation profile?**
	We agree that back loading the depreciation charge for electricity would not be appropriate. Forecast increases in demand will require further investment which will have to be paid for by future consumers. We therefore agree with the proposal to retain straight line depreciation for electricity. Given the uncertainty faced by the gas industry we agree that some form of front loading depreciation for gas distribution assets is appropriate. Front loading already applies to the assets installed as of 2002. We do not agree that the assets installed post 2002 but before RIIO-GD1 should continue to be depreciated on a straight line basis. Such an approach would result in the proportion of capex recovered through depreciation charges on 2012/13 investments being lower than that for 2013/14 investments. Applying a front loading depreciation profile to all assets would make more sense economically as well as being simpler and more transparent. For this reason we would recommend the application of a front loaded depreciation profile for all gas distribution assets. The future of gas transmission is also uncertain and, as acknowledged by Ofgem, is conditional on the development of CCS technology. Consequently, we believe it may be more appropriate to adopt a front loaded profile in transmission as well.

3	**We invite views on our proposed approach to transition.**
	Notwithstanding our concerns with the proposed changes to the asset lives and the proposed change to repex treatment in gas distribution, Ofgem's commitment to introducing appropriate transitional arrangements where moving to the use of economic asset lives in a single step would cause excessive disruption to financial markets or raise concerns over financeability is welcome. We believe transitional arrangements should also seek to achieve regulatory consistency and avoid complexity. We also welcome the acknowledgment in paragraph 4.8 of the Financial Issues annex that transitional arrangements should extend over more than one price control period where needed to allow a network to maintain financeability. **Financeability and disruption to financial markets** Paragraph 2.45 acknowledges that transitional arrangements can provide time for businesses to re-organise their financing arrangements as "immediate equity injections are not practical". Faced with a forecast of deteriorating financial ratios, rating agencies will require that potential future deterioration to be addressed immediately. Consequently, if an objective of transitional arrangements is to avoid an impractical short term requirement to raise equity as a consequence of a change in asset lives, those arrangements need to ensure credit ratings are maintained over both the short and medium term. **Regulatory consistency** We note with interest that the current consultation from The Department for Business Innovation and Skills (BIS) on the 'Principles for Economic Regulation'[24] includes predictability within its principles for economic regulation and states: • the framework of economic regulation should provide a stable and objective environment enabling all those affected to anticipate the context for future decisions and to make long term investment decisions with confidence • the framework of economic regulation should not unreasonably unravel past decisions, and should allow efficient and necessary investments to receive a reasonable return, subject to the normal risks inherent in markets In our opinion, the current proposals for electricity asset lives and repex treatment unreasonably unravel past decisions. Investors have legitimate expectations at the time they make their investment and Ofgem continues to acknowledge the importance of regulatory commitment. Changes to the asset lives and the treatment of repex such as those proposed by Ofgem contradict these legitimate expectations causing investors to price in additional regulatory risk, for which a higher return is required. Ofgem has suggested that the changes outlined in their RIIO proposals have been signalled for some time. A number of publications since December, following the consultation, demonstrate that this signalling was not as clear as Ofgem might have hoped. The additional detail in the December consultation document, on asset lives and cost of capital in particular, has triggered further analysis on the potential impact of the changes and the results of this analysis have caused some concern. **Simplicity** Transitional arrangements should be simple so that they can be easily understood by all stakeholders. Applying new electricity lives to new assets only achieves this

[24] "Principles for Economic Regulation: A call for evidence", Department for Business, Innovation and Skills, January 2011

	objective. Making step changes in asset lives during a price control is not a simple option. For example setting a life of 30 years from 2013/14, 40 years from 2017/18, and 45 years from 2021/22 means that expenditure incurred during TPCR4 will change life several times. Not only is it difficult to explain to investors why expenditure which they funded on the basis of a 20 year life suddenly changes to 30, then 40, then 45, but getting the calculations correct is relatively complex to model. Each change in life requires a comparison of the written down value using the two lives, with the book value difference depreciated over a smoothing period which would also have to be determined. Simply dividing the cost by the new life would not give the correct depreciation charge over the lifetime of the asset. **Proposed Approach** Taking into account the considerations highlighted above we believe applying new electricity asset lives to new assets only would help to minimise the increase in regulatory risk caused by the change in the basis on which investors have provided finance. Further support for this argument is provided by the position taken by DECC in their recent consultation on electricity market reform which explains the merits of 'grandfathering' current investments. It is perhaps a moot point as to whether applying a new asset life to new investment only is a transitional measure or not. After all, any increase in the proportion of repex capitalised in the RAV will only be applied for new expenditure, if at all. Nevertheless, while we note Ofgem's preference to limit transition arrangements to one price control period, the length of the transition has to be such that companies are financeable. In this context we do not believe an artificial time constraint of one price control should be imposed. Most importantly of all, National Grid would encourage Ofgem not to limit any options in its March document. Ofgem has not yet received the companies' business plans nor have they done their own financial modelling. CEPA's modelling was very high level and we have doubts about whether it adequately considered the intricacies of the regulatory regime such as the requirement to model tax cash flows etc, and the use of a nominal interest rate in those calculations. For these reasons we would encourage Ofgem to leave their options open until the receipt of company business plans. Indeed Ofgem may wish to add further transition options such as a re-profiling of income, and / or variations in the proportion of totex capitalised.
Chapter 3	
1	**Is our approach for setting the allowed return appropriate, particularly in the context of an eight-year price control?**
	The allowed return needs to be set so as to enable the network companies to be able to provide a reasonable return on the finance (debt and equity) already invested in them. In addition, as Ofgem recognise in paragraph 3.1, the allowed return also needs to be high enough to enable a notional efficient company to raise the necessary level of capital to fund the future investments that are required to meet the needs of consumers and other users of the network. Paragraph 3.2 describes 4 key principles for the approach to setting the cost of capital under RIIO: • use of a real WACC-based approach; • use of a long-term trailing average for the cost of debt, where this is updated annually;

- use of CAPM, sense-checked to other approaches, for setting the cost of equity;
- a "principles-based" approach to the calculation of notional gearing, where the size of the equity wedge reflects the company's risk exposure.

WACC based approach

We agree that it is appropriate to set allowed return on a real WACC basis, and see the benefit in terms of regulatory risk that this approach brings by maintaining consistency with past price controls. However, the inter-generational consequences and impact on financeability of this approach, which defers the RPI element of returns by indexing the RAV, need to be considered in setting other elements of the control, including the approach to asset lives, depreciation and capitalisation.

Cost of debt

We have reservations regarding the proposed cost of debt index, as explained in our responses to Questions 5 and 6, Chapter 3 below.

Use of CAPM

For investors to have confidence in the regulatory framework requires an approach that is consistent with past price controls to be adopted. Thus we agree that CAPM, sense checked by other approaches, has a role to play in the estimation of the cost of equity. However, we have concerns with any approach that relies too heavily on CAPM. These are:

- The empirical data available
- Uncertainty as to what represents 'normal' financial conditions
- The need to consider cash flow risk
- The need to ensure returns are attractive to investors

With regard to the availability of data we have two concerns, namely the limited number of data points, and difficulties in using historic data to set future equity returns.

- Since the privatisation of the energy networks there has been a progressive reduction in the number that are publicly listed. Even those that are publicly listed are typically not pure-play single network companies. This creates concern as to whether the data reviewed is sufficiently representative to be used to set equity returns.
- CAPM relies on the use of observable historic data to determine required future equity returns. The new RIIO framework of regulation fundamentally changes the risk profile of the energy networks. Significant changes to the length of the price control, the nature and strength of incentives and uncertainty mechanisms, and changes in the duration of cash flows to name but a few mean that historic CAPM data cannot reliably be used to determine the cost of equity in the future.

Recent years have seen significant changes in financial conditions with a period of easy credit being followed by a financial crisis. As a consequence we don't know what will represent 'normal' financial conditions for the upcoming price controls. We explain in our response to Question 7 and 8, Chapter 3 below that there are reasons to expect long-term shifts in global investment and savings pattern to increase the cost of capital. In such circumstances, and particularly given the increased duration of price controls under the RIIO framework, it would be unwise to base estimates of the cost of capital on recent or short-run trailing averages of risk free rate and equity

	risk premium. As a theoretical model, CAPM considers the covariance of a company's share price with the market. It is based on the principle of providing a return to compensate for non diversifiable risks. CAPM can be used to set the allowed equity return provided the cash flows of the business have been risk adjusted, i.e. that the future cash flow projections have been adjusted to consider the risks associated with those cash flows. In the past, Ofgem (and other) regulators have found it very difficult to risk adjust future cash flows and so have tended to reflect these risks in the allowed equity return. Consequently, CAPM needs to be supplemented with a consideration of the cash flow risks the networks face. We consider cash flow risk in more detail in our response to Question 2, Chapter 3. There is a presumption within the RIIO framework that equity finance will be provided at the allowed rate of return, but there is a risk that a theoretically acceptable package fails to attract finance from investors. It is essential therefore that the returns, cash flows and dividends available to equity are seen as attractive to current and future investors if the investments that are needed to meet the requirements of users of the networks are to be financeable. Questions 7 and 8, Chapter 3 consider this issue in more detail. **Notional gearing** We agree with the use of a "principles-based" approach to the calculation of notional gearing, where the size of the equity wedge reflects the company's risk exposure. We believe the notional gearing must also be set such that the notional company will have acceptable credit and equity metrics under plausible scenarios, and we believe that this consideration is most likely to determine the notional capital structure.
2	**What impact do our proposals for RIIO-T1 and GD1 have on the companies' cashflow risk, and does this have a material impact on how the allowed return should be set?**
	Cash flow risk As explained in our response to Question 1, Chapter 3, it is important to consider the impact that the RIIO proposals will have on cash flow risk. With regard to cash flow risk it is important to recognise that the impact of the proposals cannot be fully understood at this stage as the nature and strength of incentive mechanisms and scale of uncertainty mechanisms is currently unknown. Nevertheless, as highlighted below, there are a number of ways in which the RIIO proposals can be seen to be increasing the cash flow risk the networks face. It is important to bear in mind that these risks are often asymmetric and are not adequately remunerated through the CAPM framework. Given the inherent difficulties in risk adjusting the future cash flows of the networks, such risk needs to be compensated for through an increase in the allowed return. <u>Regulatory risk</u> A cash flow risk faced by the companies is regulatory risk, the risk that the regulator may reverse a previously agreed and understood position, or change the regulatory contract to the detriment of the company. In part this risk is beyond the control not only of the company but of the regulator themselves due to their inability to fetter the discretion of future regulatory or Government decisions. This risk of a resetting of the regulatory contract is most apparent during the periodic price review process. The proposed change in electricity asset lives and change to the treatment of repex are examples where previous regulatory decisions are now being changed to the detriment of company cash flows. What makes these proposals all the more

	concerning is the fact that the proposal reduces the cash flow available to companies at precisely the time that they need cash flows to make significant investments in the networks. Investors may be prepared to advance additional funds for investment, but will be less willing to advance funds due to a change in regulatory thinking. They can see an objective justification and timescale for the former and no clear reason or limit to the latter. Without this clear reason, or an absolute commitment binding future regulators to this methodology, there is nothing for investors to point to to say that cash flows will not simply be pushed out further and further at each regulatory review. <u>Duration of cash flows</u> Notwithstanding the significant concerns the asset life proposals generate for raising new equity and regulatory risk, the ENA and Oxera[25] have demonstrated that increasing the duration of cash flows will cause an increase in the required return on equity. Europe Economics[26] has attempted to challenge this with two pieces of evidence, firstly, that the shortening of asst lives for the DNOs did not cause an observable reduction in required returns, and secondly, that changes in capital allowances for oil companies did not cause changes in observed equity betas. As Oxera has explained, the CAPM framework does not adequately consider the duration of cash flows. "By construction, the one-period CAPM assumes all cash flows happen at a single point in time and cannot capture the impact of assuming different time profiles for cash flows and whether this will affect the required return on capital. Comparing the cost of capital for two series of cash flows with different time profiles is fundamentally a multi-period problem."[27] CAPM considers the covariance of a company's share price movements with the market. Changing duration would not necessarily change this covariance which is why an adjustment over and above CAPM would be required to compensate for any increase in the duration of cash flows. In this respect, Europe Economics was not looking for evidence in the right place for either of the two examples referred to. With regard to the reduction in asset lives in DPCR3, the decision to reduce asset lives was taken to maintain rather than accelerate cash flows to resolve financeability concerns as the depreciation on pre-vesting assets came to an end. At the time of that decision, financeability was considered to be a relevant factor in the choice of asset lives. The evidence quoted for the oil industry suffers both from the relevance issue referred to above and from the fact that for many oil companies their UK operations are not material to the companies, and therefore to their share prices. Inter-temporal CAPM models do exist such as Brenna and Xia (2006) and these are covered in further detail in the Oxera report[28] submitted by the Energy Networks Association in response to this consultation. That same report considers evidence and concludes "There is a substantial body of empirical evidence suggesting a relationship between cash-flow duration and required returns. Moreover, the evidence is consistent with the relationship being positive for regulated energy networks. Set against the weight of this evidence, the event study analysis provided

[25] "What is the impact of financeability on the cost of capital and gearing capacity?", Oxera report prepared for the Energy Networks Association, 9 June 2010; and "ENA Response to Ofgem's consultation "Regulating Energy Networks in the Future – RPI-X@20 Recommendations", September 2010; and "What is the cost of equity for RIIO-T1 and RIIO-GD1?", Oxera report for the Energy Networks Association, February 2011

[26] "The Weighted Average Cost of Capital for Ofgem's Future Price Control, Final Phase 1 report", Europe Economics, December 2010, Chapter 8

[27] "What is the cost of equity for RIIO-T1 and RIIO –GD1?", Oxera report prepared for the Energy Networks Association, February 2011

[28] "What is the cost of equity for RIIO-T1 and RIIO –GD1?", Oxera report prepared for the Energy Networks Association, February 2011

by Europe Economics provides only a small sample of data points, which, by the authors' own admission, is inconclusive. There remain strong grounds to believe that an increase in the duration of cash flows for regulated energy networks will lead to a material increase in the cost of capital. An indicative estimate of the magnitude of one of the components of the duration effect is 60 bp."

Intuitively there can be little doubt that an increase in the duration of cash flows would cause an increase in cash flow risk and so an increase in the required return. In the case of electricity, with a RAV asset life of 20 years, an investor could expect to receive back 40% (8 years out of 20) of their investment in a single price control, plus the allowed return. Over the life time of an asset they would be exposed to 2 ½ regulatory cycles. An asset life of 55 years reduces the proportion recovered to less than 15% and exposes them to nearly 7 regulatory cycles. When you add in the fact that the RPI element of the return an investor requires is deferred by indexing the RAV, the proportion recovered drops even further.

Deferring cash flows does not just expose the company to more regulatory cycles. It also increases the risk that assets (and therefore cash flows) may become stranded. Stranding can be the result of technological advances, economic developments or changes in Government or regulatory policy. The longer it takes to recover cash flows, the greater the risk of stranding.

Proposed changes in the nature of the price control package

Another change to cash flow risk comes from the decision to extend the price control period to 8 years. Networks will now be exposed to cost variations for 8 years rather than 5. A stronger focus on output delivery may also restrict a company's ability to respond to price variations by changing the volume of activity to compensate. In this way, subject to the uncertainty mechanisms agreed, cash flows are likely to be more exposed to cost variations.

Investor perceptions of risk

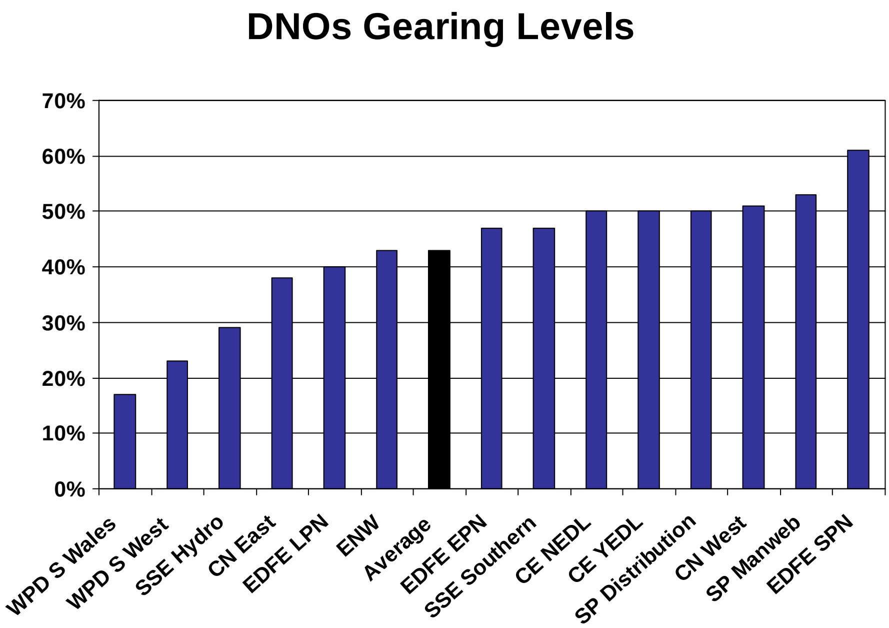
Paragraph 3.55 explains that currently "Investors view the regulated energy networks as being of relatively low risk. This is because of their predictable revenue stream, anchoring of asset values to the RAV, and the stable and transparent regulatory regime in which they operate. The result is that networks have been able to access funds at a lower cost than the market average." This view was formed at a time of strong dividends and cash flows. This history cannot be relied upon given the massive change facing the industry as indicated by Ofgem's own Project Discovery report. The RIIO proposals further weaken these positive attributes in several respects:

- The changes in asset lives and repex capitalisation put at risk the cash flows and dividends that underpin the 'low risk' view.
- In the context of an eight year control, the increased use of within control adjustments, such as the annual adjustment to revenues driven by the indexation of the cost of debt, and the proposal not to profile revenues, make the revenue stream less predictable.
- While asset values will remain linked to the RAV, the link may become less transparent to investors. In the future, capex and opex will be combined with a proportion of totex going in to the RAV.
- The new RIIO framework means that a well understood, stable and transparent regime is being replaced. Not until the new framework has become established can it be described as stable again. Almost by definition, the decision by Ofgem to change key aspects of the regulatory regime undermines the stability of that regime and the concept of regulatory

	commitment. Question 9, Chapter 3 below includes extracts from recent analyst coverage demonstrating concern with the proposed changes in the regulatory regime.
3 and 4	**3. What considerations do we need to take into account when setting the notional gearing level?** **4. Is our proposed approach to setting the notional equity wedge appropriate?**
	Approach and considerations Ofgem's proposal is to adopt a principles based approach to setting notional gearing considering the cash flow volatility of the networks. We believe the principal considerations that must be taken into account are cash flow volatility and financeability. The cash flow volatility of the companies will be affected by a number of factors including the efficiency incentive rate, incentives schemes, rewards for output delivery and innovation, uncertainty mechanisms (re-openers and revenue adjustments), and uncertainties in financial markets. Many of these have not yet been determined. With regard to financeability there is a need to consider what a practical capital structure looks like as well as the financeability assessment. Equity injections, by nature, are irregular events and so, if there is an expectation that equity will play a role in funding an increasing RAV, the notional capital structure needs to be set recognising that gearing will fluctuate from year to year. Gearing may be expected to rise above the notional capital structure for a year or two before an equity injection reduces it below that notional level. In this respect, notional gearing cannot be set at the upper limit that credit ratings may imply. Financeability also needs to be considered for the short, medium and long term. The financeability assessment of the proposals should be based on the notional capital structure and it is clear that the notional gearing level will be a key factor in determining whether or not a package is financeable. However, this assessment should not be restricted to a central case only but should also consider credible scenarios. We are facing increasingly uncertain times and it will not be sufficient simply to consider the expected cash flow outcomes. The licence and practical requirements for companies to maintain an investment grade are not limited to an 'on average' condition. Consequently, it is important that Ofgem perform a risk adjusted assessment considering credible downside scenarios. For example, with the cost of debt index it is possible for an efficiently financed company to earn returns lower than those allowed in some periods. Figure 3.2 of the Financial issues annex illustrates an iterative approach between cash flow volatility, gearing, and the cost of equity. In this respect it is interesting to note the regulatory precedent. In the GDPCR Final Proposals paragraph 9.20 Ofgem commented on the lack of empirical evidence linking gearing and equity beta. Also, through successive price controls the allowed return to equity has fallen despite increases in the notional gearing level. Notwithstanding whether the notional gearing level is a determining factor in setting the cost of equity, gearing will affect the resulting cost of capital and expected cash flows. For this reason we agree that there will need to be an iterative approach to setting the notional gearing. **Observed gearing** Given the importance of notional gearing, we are concerned that the current level of gearing has been misunderstood. There are numerous references within the

<table>
<tr><td></td><td>Financial issues annex to networks having gearing higher than was assumed in the notional capital structures for the current price controls. For example, paragraph 3.14 of the Financial Issues annex refers to network gearing of around 70% while noting the Scottish transmission companies have lower gearing. The paragraph notes that networks have achieved a “comfortable investment grade” despite the level of gearing being higher than assumed in allowances. We believe this conclusion is based on an inappropriate measure of gearing.

Our net debt to RAV gearing is quoted in the audited Regulatory accounts of NGET and NGG in 2010 as 56% and 57% respectively, i.e. below the rates assumed in the notional capital structure for both TPCR4 and GDPCR1. Further, data taken from the December 2009 PwC report for Ofgem as part of DPCR5[29] (plotted graphically below) shows gearing for the electricity distribution companies was on average 43%, i.e. significantly lower than 70%. Unfortunately, we believe Europe Economics[30], and by extension Ofgem, have therefore based much of their analysis and conclusions on an inappropriate <u>gross</u> debt to RAV rather than <u>net</u> debt to RAV definition of gearing.


</td></tr>
<tr><td>5</td><td>Is our proposed mechanism for indexing the cost of debt assumption appropriate?</td></tr>
<tr><td></td><td>Principle

We acknowledge that the proposed approach to setting the cost of debt uses similar information to that considered by Ofgem in recent price controls but, in principle, the move to setting the cost of debt based on a mechanical index of past values may not be appropriate in all circumstances. Previous price controls have recognised the value of taking different evidence and ways of estimating the cost of debt into account, and this more flexible approach should be retained. This issue is illustrated quite nicely by figure 3.3 of the Financial Issues annex which gives an example where the actual cost of debt exceeds the allowance for every year of the price control.</td></tr>
</table>

[29] “Advice on the cost of capital for DPCR5: Final report”, PwC for Ofgem, December 2009, Table 33

[30] “The Weighted Average Cost of Capital for Ofgem’s Future Price Control, Final Phase 1 report”, Europe Economics, December 2010, paragraphs 4.25 and 4.27

	Ofgem has previously stated that the proposed cost of debt index will reduce risk for companies because a network will know that even if an efficiently raised bond costs more than the index at the date it is issued (due to rising interest rates) they can be confident that the costs will be recovered eventually (due to the 10 year trailing average). However, figure 3.5 of the Financial Issues annex demonstrates that the average tenor of bonds is 18.6 years so the index would only include that bond for just over half of its tenor. Further, in 3.18 and 3.19 Ofgem appear to contradict their own arguments that debt costs will be financed by the index. In responding to network arguments that structuring a debt profile to more closely match the index to reduce risk would be costly and inefficient Ofgem avoid the question and simply say it is for networks to choose how they finance themselves. **Practical Issues** In terms of practical implementation details, with the exception of being “fully mechanistic”, as explained above, we agree with the criteria used to evaluate options. We also agree that the requirement in paragraph 3.24 for the index to “accurately reflect the cost of debt for an efficient company” carries a high weight. However we have concerns regarding: • The choice of indices • The tenor of debt • The omission of a significant tranche of efficient debt finance costs • The period of the trailing average. and • The failure to fund the inflation risk premium We would make the following points on the proposal to use an average of Bloomberg 10 year BBB and 10 year A corporate bonds: • We agree with the use of GBP corporate bonds as this will preserve efficiency incentives far more effectively than utility bonds. • We do not agree that the index should be an average of A and BBB bonds. Contrary to the comments in paragraph 3.29 that “licensees are roughly equally divided between a broad A rating (covering A+/A/A-) and a broad B rating” analysis shows that the vast majority of energy networks are rated between A- and BBB. Further, changes in the duration of cash flows are likely to put further pressure on credit ratings. We would therefore propose an average of the A- and BBB indices. • We do not agree with the use of 10 year bonds. The networks invest in long life assets and often raise debt with a longer tenor than 10 years. Figure 3.5 showed the average tenor is 18.6 years so an index of 10 year bonds is not representative of the costs efficiently incurred by the networks. While Ofgem state that the difference between 10 year bonds and longer dated issues is not material, as a matter of principle, we believe it would be more appropriate to move to the iBoxx 10+ index which would include longer dated issues. As noted above, a key objective of the index is to reflect the efficient costs of debt finance. Our response to Question 6, Chapter 3 below explains that the index as currently proposed does not cover significant costs associated with debt finance such as issuance fees, facility fees, commitment fees, new issue premia, credit agency fees, and the costs of carrying cash etc. The index as proposed therefore fails in principle to fund the full efficient costs of debt finance and should be amended to make allowance for such costs. With regard to the trailing average:

	• We agree that a simple average rather than a weighted average is preferable on the grounds of simplicity and transparency. • On the 10 year length of the trailing average, if debt has an average tenor of 18.6 years it would seem to make sense to have a longer trailing average. Finally, we have concerns that the index does not adequately capture the risks associated with inflation nor fund the costs of mitigating them. The index uses nominal bond yields to derive a debt premium which is then added to a real risk free rate. Although this works in principle for debt which is issued as RPI linked, network companies typically have to raise fixed or floating rate nominal debt because the market for corporate RPI linked debt is not sufficiently developed. This mismatch can lead to the real cost of debt actually incurred for issued nominal rate debt being higher than the allowed real cost of debt. The reason for this is because the implied inflation rate from the proposed approach may be overstated due to the demand for index linked gilts as an effective hedge against inflation risks. According to recent research by the Bank of England, this inflation risk premium has been estimated for the UK to have been approximately 30 basis points for investments with a five year maturity[31]. This means the proposed approach for setting the allowed real cost of debt would be approximately 30 basis points lower than that actually incurred for debt raised with nominal rate coupons.
6	**How should we account for the costs of issuing debt?**
	As noted in the response to Question 5, Chapter 3 above, a key objective of the index is to reflect the efficient costs of debt finance. As currently defined the index would fail to cover the efficient costs of debt finance. These include (but are not limited to): • Debt issuance fees • New issue premia • Bank facility fees • Credit rating agency fees • Commitment fees • The costs of carrying cash These costs are typically reported as finance costs in accounts and so are not covered by operating cost allowances. In the case of debt issuance fees Ofgem has suggested in paragraph 3.37 that these costs do not need to be considered because companies have historically managed to raise debt at rates lower than the proposed index and the outperformance should fund such costs. As a fundamental principle this position cannot be justified, not least because such outperformance cannot be relied upon to continue. Several aspects of the RIIO proposals can be expected to put considerable pressure on credit ratios, and the debt premia that energy utilities have to pay, relative to the corporate market. These include: • An increase in the duration of cash flows due to changes in asset lives and repex capitalisation. • Increased use of incentives which may increase the volatility of cash flows

[31] Joyce, M., Lidholdt, P. and Sorensen, S. (2009) ‘Extracting inflation expectations and inflation risk premia from the term structure: a joint model of the UK nominal and real yield curves’, Bank of England working paper 360.

- Exposure to cost variances for eight years rather than five

In this context, it is clear that any past outperformance cannot be relied upon in the future to fund the efficient costs of debt finance currently ignored by the index.

Further, it is difficult to reconcile Ofgem's position on debt issuance costs with that adopted for equity, where a specific allowance is provided to cover the costs of issuing equity.

An appropriate way to account for these costs would be to add a pre defined number of basis points to the cost of debt index. We note that paragraph 1.28 of the DPCR5 Final Proposals Financial Issues document stated that there was a spread between the allowed cost of debt and the value of the trailing cost of debt index of circa 30 basis points specifically to fund transactional costs of this nature. The table below compares the level of the trailing index on the last working day before the start of a relevant price control, with the cost of debt allowed for that control. The table illustrates that Ofgem has consistently set the allowed cost of debt approximately 30 basis points higher than the trailing index (which Ofgem themselves claim has long been the basis on which the cost of debt has been set).

	TPCR4 (30/3/07)	GDPCR1 (31/3/08)	DPCR5 (31/3/10)
Allowed cost of debt	3.75%	3.55%	3.60%
Value of trailing average index	3.44%	3.29%	3.20%

In addition, we note that transaction costs such as those covered by this response were specifically included within the cost of debt allowed in the recent water reviews. Ofwat said "We have set the cost of debt at a level that allows companies to meet transaction costs, commitment fees and costs associated with the maintenance of an appropriate level of liquidity. We calculate these costs to be 0.2% on the cost of debt overall, factoring in a view of these costs under current and more benign economic conditions."[32]

7 and 8

7. Is our range for the equity beta appropriate for the network companies? What factors might mean that we should use different equity betas for the different sectors and/or companies within a sector?

8. Does our overall range for the cost of equity correctly capture probable risk for RIIO-T1 and GD1?

Approach to setting the cost of equity

Our response to Question 1, Chapter 3 above explains that while CAPM has a role to play in setting the cost of equity, we would have a number of concerns with any approach that relied too heavily on CAPM, namely:

- The empirical data available
- Uncertainty as to what represents 'normal' financial conditions
- The need to consider cash flow risk
- The need to ensure returns are attractive to investors

Our response to Question 2, Chapter 3 details how the RIIO proposals increase cash

[32] Ofwat November 2009 2010-15 Final Determination, section 5.4.4

	flow risk, particularly when it comes to regulatory risk and asset stranding risk. That same response explains that an increase in the duration of cash flows and cash flow risk need to be reflected in the allowed equity return. The remainder of this response comments on three things: • 'Normal' financial conditions • The range for the equity beta • The need to ensure equity returns are sufficient to attract equity This response concludes with a selection of comments taken from recent analyst coverage of National Grid. **'Normal' financial conditions** As mentioned in our response to Question 1, Chapter 3, we have concerns with trying to use historic data to derive expected future returns. An underlying assumption of the proposed CAPM approach is that an appropriate cost of capital for an 8 year RIIO price control that will not even start for another two years can be set using historical information, with a particular focus on the relatively recent past (i.e. the past decade). The past decade initially saw a period of relative stability, combined with freely available credit and a generally declining risk free rate (as implied from index-linked gilt yields - see Europe Economics report Figure 3.2). This was followed by a period of almost unprecedented financial instability (particularly in 2008 and 2009), accompanied by reduced credit availability, higher risk-free rates, higher debt spreads, and significant instability in equity markets. The financial conditions in the preceding years are now seen as a precursor of the financial crisis, suggesting that neither of these periods can be seen as "normal". Whilst it would be understandable if regulators were reluctant to base an estimated future cost of equity on the conditions at the height of the financial crisis, it would be equally inappropriate to assume that the current conditions, or indeed those in the years leading up to 2008, will again be seen during the period from 2013 to 2021. Further support for this proposition comes from McKinsey's December 2010 report "Farewell to cheap capital? The implications of long term shifts in global investment and saving", which analyses the reasons for low and declining capital costs over the past 3 decades, and concludes that the conditions that led to cheap capital (not just in the UK but globally) may be expected to reverse and lead to a higher cost of capital in the next two decades. While we do know that the last decade was not 'normal' we do not know what the new 'normal' will be. Faced with such uncertainty, great care needs to be taken in setting an assumed cost of equity (within the allowed WACC). It is not only inappropriate to place weight on current spot values of the risk free rate and equity risk premium, but a 5 year trailing average (as shown in Figure 3.11 of the Financial Issues annex) or even 10 year trailing average cannot be considered a sound basis on which to estimate future values. In such conditions, the cost of equity should be based on long term average values of the risk free rate (2.5%[33]) and equity risk premium, using values that are consistent with the directly observed long-run total

[33] "Report on the Cost of Capital provided to Ofgem", Smithers & Co. Ltd., 1 September 2006, page 4 (1st bullet point). Note also that the PwC report "Office of Gas and Electricity Markets - Advice on the cost of capital analysis for DPCR5 Final Report", 1 December 2009, Summary and Conclusions final sentence, suggests that 2.5% is "consistent with the mid-point level for the real RFR that has generally been used in regulatory determinations since 2000."

	market equity return which is generally recognised to lie in the range from 6.5% to 7.5%[34], although a value of 8% was more recently suggested as the long-run value of total market equity return in DPCR5[35]. **Equity beta** As explained in Question 1, Chapter 3 above, limitations in the empirical data available make it difficult to derive an appropriate equity beta to use. It is also important to recognise that at this stage the nature and strength of incentive mechanisms and scale of uncertainty mechanisms are currently unknown making it difficult to comment both on the impact they would have on beta and on the range for the cost of equity. In previous price controls Ofgem has given weight to an aggregate return on equity approach, i.e. using the total long-run equity market return, rather than a value derived from CAPM with an assumed equity beta value. This was the approach in DPCR4, TPCR4 and GDPCR[36], and reflects the greater stability of total market return (rather than its individual components, i.e. equity risk premium and risk free rate) and also observed instability in beta values[37], which is particularly important given that a stable beta is an assumption which underlies CAPM. The information and diagrams of rolling betas presented in the Europe Economics report show that their beta values remain unstable, and that there is similar instability in the betas of the water companies and European energy companies that Europe Economics seek to use as comparator companies[38]. In the light of this, regulatory consistency would suggest that weight should be given to the total market return approach, which in effect applies an equity beta of 1. In addition to these general points, we have reservations regarding the basis of the equity beta range proposed. • The gearing values that Europe Economics have used in de-levering observed equity betas appear incorrect as explained in our responses to Questions 3 and 4, Chapter 3 above. Use of the correct gearing figure would lead to a higher asset beta. • Fundamentally, Ofgem has previously questioned the validity of the conventional, mechanistic relationship between gearing and cost of equity which is assumed in the Europe Economics analysis (defined at paragraph 4.25).

[34] "A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K.", Smithers & Co Ltd, 13 February 2003, page 49; and "Report on the Cost of Capital provided to Ofgem", Smithers & Co. Ltd., 1 September 2006, page 4 (1st bullet point).

[35] "Office of Gas and Electricity Markets - Advice on the cost of capital analysis for DPCR5 Final Report", PwC, 1 December 2009, Summary and Conclusions: page 2 gives Risk Free Rate between 2% and 2.5, where 2.5% is the long-run rate, i.e. "*consistent with the mid-point level for the real RFR that has generally been used in regulatory determinations since 2000*", and then on page 3 for EMRP "*Taking a longer-term approach, we consider that a range of 4.5% to 5.5% is appropriate. The upper end of this range is broadly consistent with long-term evidence on the actual excess returns on equities in the UK*." Thus, a long-term view of total market return would be 2.5% + 5.5% = 8%, at the top end of the PwC range from 6.5% to 8%.

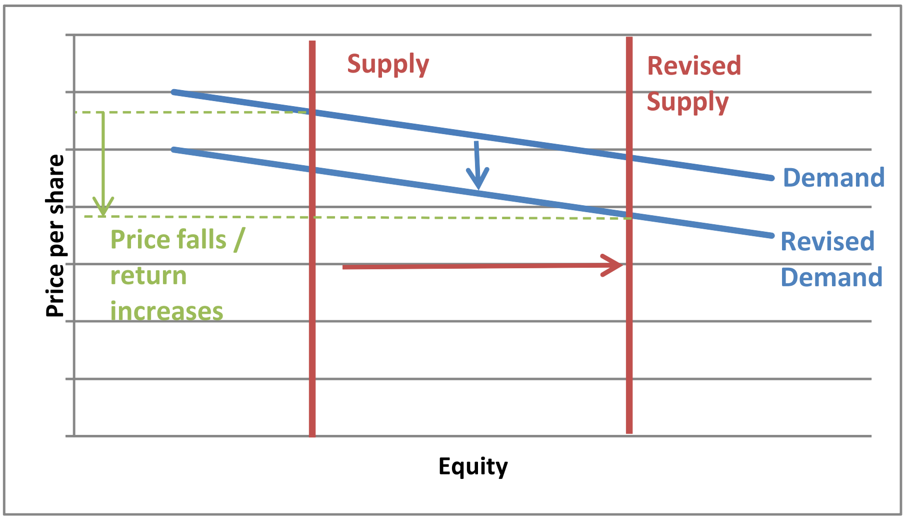
[36] "Electricity Distribution Price Control Review Final Proposals", Ofgem, November 2004, paragraph 8.43; "Transmission Price Control Review: Final proposals", Ofgem, December 2006, paragraph 8.15; "Gas Distribution Price Control Review: Final proposals", Ofgem December 2007, paragraph 9.18.

[37] "Electricity Distribution Price Control Review Final Proposals", Ofgem, November 2004, paragraph 8.42; "Gas Distribution Price Control Review Fourth Consultation Document", Ofgem, March 2007, paragraph 6.5.

[38] "The Weighted Average Cost of Capital for Ofgem's Future Price Control, Final Phase 1 report", Europe Economics, December 2010, figures 4.1to 4.4, 4.6 and 4.7.

	In the context of considering the appropriateness of the proposed range of equity beta, it is important also to consider the values of the risk free rate and equity risk premium that have been used in deriving the cost of equity range (4.0% to 7.2%). In this regard, we note that the bottom half of the resulting range for the total market return (5.4% to 7.5%) is below the range used in past controls (generally 6.5% to 7.5%)) which is based on long-run values[39]. The range appears to be based on long term historical averages for the equity risk premium combined with relatively short term risk free rate data. In essence the approach combines a historically average risk premium with a historically low risk free rate. Such an approach is likely to understate the required return. In DPCR5 it was recognised that use of short-term values and trends would lead to a higher cost of equity, but Ofgem rejected these values in favour of a value derived from long-run values on the basis that finance theory indicates that the cost of equity should be constant. It would be asymmetric to adopt a different approach now, only just over a year later, when short term values (particularly some risk free rate information) could lead to a lower value. As explained above, the CAPM model should be applied using long-run values, as any recent information cannot be taken as the "new normal" financial conditions that will be representative of the long-run cost of equity following the financial crisis. **Returns to attract equity** Finally, given the need to finance increasing investment in the energy networks, there is a need to ensure that returns will be sufficient to attract the required investment. The economic principles of supply and demand can be used to demonstrate that if there is a requirement to inject equity, the returns to equity need to increase. While the market for listed equity is liquid, it cannot be described as perfect given the existence of transaction costs and lack of perfect information (as illustrated by the impact announcements or investor notices can have on share prices). In the absence of a perfect market, the demand curve is downward sloping. In this context, an investor will only demand more shares in a company if the price falls, i.e. their expected returns on the investment increase. In the absence of any information signals, an increase in equity will move the supply curve to the right causing the equilibrium share price to drop, i.e. required returns to rise. However, equity issues also send information signals to the market. That information may result in a downward movement in the demand curve causing an even greater reduction in price and increase in required returns. In the context of a regulated network, the best case scenario is perhaps that the equity is required to fund future capex. If such investment attracts the same return as the current RAV, investors may be concerned about increased construction risk or a dilution of returns with existing incentive performance spread over a larger equity base. However, the RIIO proposals for asset lives and repex treatment extend the duration of cash flows. Investors will see deterioration in the cash flows of the business, and in the dividends they receive. The best case is that some investors will consider the

[39] "Electricity Distribution Price Control Review Final Proposals", Ofgem, November 2004, paragraph 8.44; "Transmission Price Control Review: Initial proposals", Ofgem, June 2006, paragraph 8.3 and Appendix 9 paragraph 1.13; "Transmission Price Control Review: Final proposals", Ofgem, December 2006, paragraph 8.5; "Gas Distribution Price Control Review: Final proposals", Ofgem December 2007, paragraph 9.18; "Electricity Distribution Price Control Review Initial Proposals – Allowed Revenues and Financial Issues", Ofgem, August 2009, paragraph 1.16; and "Electricity Distribution Price Control Review Final Proposals – Allowed Revenues and Financial Issues", Ofgem, December 2009, paragraph 1.37 and Table 1.6.

	impact to be NPV neutral, but for others the short term deterioration in dividends and cash flow will be seen negatively, pushing the demand curve down and further increasing the return required to attract new equity. The graph below illustrates these impacts.  In practical terms, the equity markets do not sit on large amounts of cash looking for a home. In order to fund additional equity investments in energy networks this cash will have to be moved from other competing investments. The yields and returns available on those competing investments will have to be considered by Ofgem when determining an appropriate allowed return on equity. To summarise, CAPM has a role to play in estimating the cost of equity. However, the RIIO proposals increase the cash flow risks the networks are exposed to, risks which CAPM does not adequately address. There is therefore a need to consider this cash flow risk in setting the cost of equity. More fundamentally though, we are entering an era where the challenge is no longer just about the return current investors require on their investment but is increasingly about allowing a return that will attract new investors and sources of finance. In the absence of further information on the strength of incentives and uncertainty mechanisms it is not possible to be definitive on the required cost of equity at this stage. However, one thing that is clear is that with increasing cash flow risk and a need to set an allowed return that will be attractive to investors, the cost of equity that is allowed will need to be at least at the top end of the range proposed by Ofgem. **Analyst comments since December RIIO document** The comments below are taken from recent analyst coverage of National Grid and illustrate many of the issues raised in this consultation response. • *"There may be debate about whether [Ofgem's return range] is sufficient to reflect the risks associated with a longer control period and changes to asset lives."* • *"Ofgem still plans to extend depreciation lives in the name of technical correctness, reversing its previous adjustments to accommodate the sector's investment profile. These changes are theoretically NPV neutral, but will have implication for cash flows, and we are not convinced they are either necessary or justified."* • *"We believe it is important to distinguish between theory and the real world. Ofgem needs to work hard during the review process to give the comfort*

	necessary to maintain investor appetite in the sector." Bank of America Merrill Lynch - Fraser McLaren - December 2010 • *"We are already concerned that this process will lead to a settlement that is unattractive to equity investors. The UK requires enormous investment in its energy network infrastructure and the positive sentiment coming from government and Ofgem does not necessarily match up with some of the detail in these documents."* RBS - Iain Turner - January 2011 • *"[The latest Ofgem proposals] pose substantial risks to cashflow and earnings and could therefore put the capital structure and the sustainability of the dividend at risk."* • *"It is still in early days...but in our view, these proposals raise [NG's] regulatory risk profile."* • *"Even taking a generous interpretation suggests that these proposals could potentially reduce the long term earnings and cash flow generation by a meaningful amount – c20% from 2013 onwards. Obviously a reduction in earnings makes the current dividend level, and the current balance sheet structure look a good deal less certain. For example it would probably reduce dividend cover to only around 1x."* • *"It now appears clear to us that if NG's capex remains close to current projected levels (around £5bn p.a.), there could be the requirement to strengthen the balance sheet with disposals – although this is not straightforward, and may need a revisit of the dividend – or further equity issuance. The Ofgem proposals would only exacerbate this."* Morgan Stanley - Bobby Chada - January 2011 • *"Equity investors may well not accept the "jam tomorrow" investment proposition.. [And] we believe that this could lead to such stocks underperforming significantly."* Unicredit - Scott Phillips - January 2011 • *"At a presentation on 1 February, Ofgem set out more of its thinking. The regulator is keen to try to assure investors that (1) it is taking a measured, balanced approach, (2) that it will ensure that companies can finance their functions, and (3) that it is seeking to attract, not deter, investment.* *We have no doubt that this is Ofgem's intention, but its proposals contain some serious changes that we feel do not fit with the aims stated above – some appear to be change for changes sake… We also doubt that Ofgem really appreciates all of the concerns from a listed equity market perspective."* Morgan Stanley - Bobby Chada - February 2011
9	**Is the ex ante approach to the cost of raising equity, with a true-up at the next price control review appropriate for RIIO-T1 and GD1?**
	In TPCR4 the key elements of the mechanism were: • Ofgem assumed that licensees would be able to raise additional equity when necessary; • Ofgem estimated the amount of new equity that was likely to be needed using their price control model and used this as the basis of an ex-ante allowance

	for the cost of raising new equity; • this ex-ante allowance was set equal to 5% of the value of the additional equity that was expected to be needed; • there was then an ex-post adjustment to reflect the actual level of investment during TPCR4. Ofgem's approach to financeability takes equity for granted and assumes that equity can be raised to ease financeability concerns. As explained in Question 8, Chapter 3 above, if the package is not sufficiently attractive to new equity the assumption in the first point above may not hold. Considering the remaining elements of the mechanism: • it remains appropriate to set an ex-ante allowance based on a central scenario of expected future investment, with an ex-post adjustment to reflect actual levels of expenditure. This central scenario should include cash flows from expected load related expenditure which may be the subject of uncertainty mechanisms; • in recognition of the longer duration of future controls and the greater uncertainty over future investment levels under RIIO an ex-post adjustment should be made after 4 years at the mid-control review, as well as at the end of the control; • it remains appropriate to base the allowance for the cost of raising new equity on the amount of new equity needed in the notional gearing structure to maintain financeability (as assessed by the levels of credit metrics needed for an investment grade credit rating), rather than basing the ex-ante allowances or ex-post adjustments on the actual amounts of new equity raised. • The ex-ante allowance and ex-post adjustment should continue to be based on 5% of the new equity required in the notional structure. In National Grid's May 2010 Rights Issue, the direct costs of raising new equity were 3.5% of the equity raised (£111M out of £3.2bn). However, this was the largest ever rights issue in the UK for organic investment growth and the largest by a UK privatised network utility. Smaller rights issues may be expected to incur higher direct costs. In addition, there are indirect costs of raising new equity, including the costs (for investors) of selling other investments to take up the rights, and when these considerations are taken into account a 5% allowance for the costs of raising new equity continues to be reasonable. In addition, one significant extension should be made to the TPCR4 mechanism, namely to extend the approach to fund the cost of any new (notional) equity at the start of the RIIO controls, where this is needed to bring the notional gearing at the end of TPCR4 (or GDPCR) into line with the opening (notional) gearing for RIIO-T1 (or RIIO-GD1). Clearly, it would be a major oversight if new equity that is needed in the notional gearing structure during a control is funded, but any new equity needed to bring the rolled forward gearing from one control to Ofgem's assumed opening gearing at the next control is not funded.
Chapter 4	
1 and 2	**1. Have we identified the correct equity and credit metrics?** **2. Do the rating agency levels quoted provide the most appropriate levels?**
	Equity metrics In considering the metrics of interest to equity investors, it should first be noted that

	these investors take a keen interest in a company's credit ratings and in the financial ratios, metrics and other considerations which lie behind these. There are, though, additional metrics of particular interest to equity (as opposed to debt) investors. Paragraph 4.2 identifies the key ratios for equity investors as Notional RAV/EBITDA and Regulated Equity/Regulated Earnings. In addition, given the importance of dividends to investors in the utility sector, and the resulting need for the regulatory framework to allow consistency in dividends to be maintained (or otherwise allow a significantly higher cost of equity), these ratios need to be augmented by a dividend yield measure, such as Notional Dividends/Notional Equity, and a dividend cover ratio. We note that Ofwat considered dividend cover to be a key ratio in their November 2009 Final Proposals and the importance of dividends is clear from the analyst comments reproduced in the response to Questions 7 and 8, Chapter 3. For this reason, we believe the dividend yield should be maintained in the modelling even if equity is required. If Ofgem acknowledge the importance of dividends to investors we believe it would be helpful to clearly emphasise this in the March document. For consistency with the rest of a price control, the projected values of these metrics need to be assessed for the licensee under the assumed notional gearing and capital structure. **Credit metrics** From the simple discussion at paragraphs 4.1 to 4.5, it does not appear that Ofgem have appreciated the complexity and sophistication of the rating agencies approach to assessing credit ratings, which cannot be reflected by a narrow focus on a small number of financial ratios. It is important to recognise that financial ratios are just one of the factors that the rating agencies take into account in assessing credit ratings. Other factors, especially the stability of the regulatory environment and ownership model are equally important. It is therefore extremely important that Ofgem take care not to jeopardise the current positive view of the UK regulatory framework through the changes that the RIIO model will bring, and should avoid breaking with established precedents. All three main rating agencies (Moody's, Fitch and Standard and Poor's (S&P)) stress the importance of transparency, consistency and predictability in the regulatory framework as part of their assessment of a network's business and financial risk. They recognise that changes in regulation such as those proposed under RIIO could raise financing risk and as a result increase the credit risk profile of the network companies. By way of example, if Ofgem were to change depreciation lives for electricity transmission or distribution, the effect on cash flow will be taken into account in assessing credit risk. In assessing credit ratings, the rating agencies typically have a particular focus on the values of credit metrics over relatively short timescales, which might typically be over 3 to 5 years. As a result the credit metrics need to have values that are consistent with the targeted credit rating in the short term as well as in the medium and/or long term. Longer-term considerations (both qualitative factors and the values of financial ratios) do matter[40] but it is not sufficient for Ofgem to focus on the medium and long term only as this will not ensure financeability. Given their financing duty, Ofgem must take into account the requirement for companies to be able to maintain the key metrics at acceptable values across all timeframes. It is no answer for Ofgem (see Paragraph 4.5) to state "the onus will be on the company to resolve the situation" where there are shortfalls in metrics.

[40] If rating agencies were to have concerns regarding the reliability of the future regulatory framework, this would affect credit ratings today

Ofgem's assessment of financeability applies only to the notionally financed licensee so they calculate and assess the metrics for the licensee under their own choice of notional gearing. Deficiencies cannot therefore be resolved by the company – they can only be resolved by Ofgem revising the assumptions in the price control proposals, such as the notional gearing or allowed return on equity.

Ofgem also need to recognise both short-term and medium/longer-term considerations where their financial modelling indicates that new equity will be needed in a licensee's notional capital structure in order to maintain an investment grade credit rating. Whenever new equity is required to maintain a rating, this needs to be raised immediately rather than waiting for ratios to deteriorate: debt investors and rating agencies cannot assume that new equity will always be available at the point in time that a future need arises. Whilst this can result in an "inefficient" capital structure for some years, it is unavoidable, and so needs to be recognised and funded in setting the allowed return.

With regard to credit rating metrics themselves, Paragraphs 4.2 to 4.4 identify the key metrics as Gearing and PMICR (or adjusted cash interest cover),[41] with some consideration also being given to FFO interest cover and RCF/net debt. Whilst PMICR and net debt/RAV are used by some agencies, they are not used in isolation and neither are they used uniformly by all of the agencies. This was recognised in Europe Economics' report for Ofwat as part of the 2009 price review in the water sector, which said *"… different agencies put different weight on different ratios and so there is no single set of ratios which captures the approach of all the rating agencies."*[42] A strong focus on PMICR as one of only two key ratios (the other being gearing) is inappropriate, given that Ofgem has previously expressed reservations about the use of PMICR[43], and the fact that, as Ofgem previously noted, it reduces to a function of gearing and cost of capital. As Ofgem noted in GDPCR, "The agencies make it clear that this is only one ratio, and that they rate companies based on a range of financial ratios, having regard to compliance with short-term target levels as well as medium-term trends, a review of financial strategy, and other qualitative judgments including business risk assessment."[44]

Instead, for an assessment of financeability to have any value and relevance, Ofgem must continue to reflect the approach of <u>all</u> the agencies and look at a wider range of ratios as well as the qualitative factors referred to above. Given that different companies and debt issues are rated by different agencies, it is important to consider the approach of all the main ratings agencies and the approach they use. In this respect, given that the energy networks are largely held within larger corporate groups, Ofgem also needs to consider the fact that some of the agencies do not look at the licensee, but review the group position and then rate subsidiaries accordingly rather than rating the licensees in isolation. This consideration further emphasises the need to consider a range of ratios and the approaches of all of the agencies.

Regulatory precedent and the need for a consistent approach also indicate that a wider range of metrics than just Net Debt/RAV and PMICR need to be considered. In TPCR4 Ofgem principally considered Debt/RAV, FFO/RAV, and FFO+ Interest/Interest, whereas in DPCR5 Ofgem principally considered the values of Funds From Operations ("FFO")/Interest, Retained Cash Flow ("RCF")/Debt, and Debt/RAV. In the financeability assessment in their most recent price control,

[41] The calculation of PMICR (or adjusted cash interest cover), and indeed other ratios, differs between the main rating agencies

[42] "Cost of Capital and Financeability at PR09 Report by Europe Economics", 21 July 2009, para 10.23.

[43] "Gas Distribution Price Control Review Fourth Consultation Document", Ofgem, March 2007, Appendix 10 paragraphs 1.10 to 1.27.

[44] "Gas Distribution Price Control Review Fourth Consultation Document", Ofgem, March 2007, Appendix 10 paragraph 1.3

	completed in December 2009, Ofwat considered Gearing (Net Debt/RAV), PMICR, FFO/Net Debt, FFO/Interest, RCF/Debt and Adjusted Cash interest cover, these ratios being adopted following consultation with the rating agencies. **Metric levels** In accordance with Ofgem's financing duty and to provide the necessary comfort on headroom to the rating agencies, the price control must allow a reasonably efficient licensee with the assumed notional gearing / capital structure to maintain a comfortable investment grade credit rating under plausible scenarios. Thus, Ofgem's assessment of the key credit ratios needs to be carried out for the assumed notional capital structure under different scenarios, and not just for a base case. Given the practical difficulties associated with doing this, it would be more appropriate for the metrics to be targeted at a rating level of "A-" rather than "BBB", consistent with approach adopted by Ofwat at PR09[45]. In considering the appropriate values of the individual metrics or ratios, it will be important to recognise the approach of the ratings agencies. The table in Figure 4.1 of the Financial Issues annex is overly simplistic, even if it were extended to include a wider range of financial ratios. Rather than having absolute cut-off threshold values, the agencies have ranges of expected values for the metrics corresponding to each different rating. Taking account of qualitative factors and of the values of other ratios the agencies can consider the rating which best reflects the overall financial position of a company and the likely ability of the company to service its borrowings. Even if the values of particular indicators (e.g. Ofgem's current proposed primary ratios, i.e. PMICR and gearing) lie within an agency's range for a particular credit rating, if other ratios or qualitative considerations (e.g. a lack of regulatory consistency) give cause for concern, the agency may set a lower credit rating. This further illustrates why a wider range of metrics than those currently identified by Ofgem need to be calculated and reviewed, and Ofgem's proposed approach needs to be reconsidered and extended. Previous analysis by Ofgem[46] has shown how the key ratios can impose constraints on other elements of the price control (in particular gearing and assumed asset lives), and these constraints can become tighter under certain circumstances, e.g. when inflation increases, as is currently expected in the later years of the first round of RIIO price controls[47]. Ofgem will need to be mindful of these constraints in setting the parameters of the RIIO price controls so as to maintain network financeability.
3	**We invite views on the approach to assessing the appropriate level of notional gearing.**
	The response to Questions 3 and 4, Chapter 3 above cover this question.
Chapter 5	

[45] Ofwat's Final Determination on Future water and sewerage charges 2010-15, Section 1, Key Messages:
"*We have targeted financial ratios that are consistent with an A-/A3 credit rating. The majority of companies are in this position. Where one particular indicator (and in a small number of cases, two indicators) for a single rating agency may not meet the required threshold, we ensure that it meets the criteria for a strong BBB+/Baa1 credit rating*."
[46] Joint Ofgem and Ofwat paper, "Financing Networks: A discussion Paper", February 2006, Annex A
[47] The Bank of England website provides data on the implied "break-even" inflation rates - both spot and forward – derived from nominal and index-linked gilts, for maturities between 2.5 and 25 years in intervals of 0.5 years

1	**Do you agree with modelling tax based on the proposals in the June 2010 Budget?**
	The most important consideration is the principle of fairness. The proposals within the June 2010 budget are known changes to tax rates which are expected, but not all legislated, to occur. It does not seem unreasonable therefore to reflect them in the tax modelling. However, regulatory precedence has been to use extant rates which have the advantage of not assuming a legislative change in rates which may not happen, particularly in the context of the current state of public finances. Of the options presented, the fairest would therefore seem to be either option b (using June 2010 budget rates with outturn rates as a pass through) or option c (using extant rates with pass through of any changes in rates). Under these options consumers and licensees are shielded from any upside or downside exposure to the tax rates. We believe a wider issue worthy of comment is the inter play between the tax trigger and the proposed cost of debt index. Paragraph 1.4 of appendix 3 of the Financial Issues annex states that the trigger specifically includes the effects from: • Changes in relevant legislation, e.g. a finance act • HMRC interpretations of legislation • New precedents under case law, and • Changes in accounting standards The document makes the further point that while changes in the first of these may be easily measurable, the latter three may not. The proposed cost of debt index will result in an annual adjustment to revenues. The cost of debt allowance impacts on revenues in two primary ways, through the return on the RAV, and through the tax allowance due to the tax shield on debt. On the assumption that the annual adjustment to revenues for the cost of debt index includes modelling the tax allowances it would be logical to include all changes in tax legislation in that modelling. Under these circumstances it would make sense to always use the tax legislation that will be in force for the relevant year, in which case legislative changes in corporation tax and capital allowance rates etc would no longer need to be included within the scope of the tax trigger.
2	**Do you agree with modelling tax under UK GAAP pending adoption of IFRS reporting with any changes to be subject to the tax trigger?**
	Ofgem's proposals on the relevant tax rates to use covered by Question 1 above take an approach of reflecting now changes that are expected to occur. Arguably, this same principle should be applied to known changes that are expected to occur as a consequence of the expected move to IFRS. Also, it is likely that there will be further clarity and certainty regarding the expected timing and impact of the move to IFRS reporting as we progress through the price control process. If it becomes clear that the move to IFRS reporting will definitely happen from a given date, the tax modelling should reflect the expected outcome. As with our response to Question 1, our primary concern is fairness. In principle we have no objection to modelling on the basis of UK GAAP with the IFRS related

	changes being covered by the tax trigger provided such an approach would be equitable. However, this will not be the case for two reasons. • First it is clear from paragraph 1.10 of appendix 3 that the tax impact of changes in accounting standards will only be adjusted in revenues after HMRC has agreed the relevant tax return. By the time any agreed change to revenue allowances can be passed through in the form of charges to consumers, there could be a delay of 3 years or more[48] which is clearly unacceptable given that the impacts will be, if indeed they are not already, known and well understood by the time of Final Proposals. Given the materiality of the amounts involved such a delay could put the financeability of companies at risk. • Second, the current expectation is that IFRS accounting will result in a material increase in tax costs. Under such circumstances, as currently proposed the dead band of the tax trigger would be an asymmetric downside only risk which would have to be reflected in the allowed rate of return. This could be addressed by changing the way in which the dead band works as discussed in our response to Question 3 below.
3	**Views are invited on the size of the dead-band?**
	The purpose of the dead band is to avoid immaterial changes in charges caused by changes in the factors detailed in paragraph 1.4 of appendix 3 to the Financial Issues annex. For changes within the dead band, licensees are exposed to small variations in tax costs, whether they are positive or negative. Of more significance is the adjustment made if the tax trigger goes outside the dead band. As currently proposed, if the tax trigger is activated the adjustment only covers the difference in tax costs excluding the dead band. Ordinarily this may be a symmetric arrangement but for the gas distribution businesses, the move to IFRS reporting will result in a material increase in tax costs, probably from 2014/15. Under such circumstances the dead band of the tax trigger would be an asymmetric downside only risk which would have to be reflected in the allowed rate of return. We would propose that the dead band should be used only as a threshold to determine whether an adjustment to revenues is required. In the event that a change in tax costs goes beyond the dead band, revenues should be adjusted in full for the change in tax costs. Such an arrangement would avoid the need to increase the cost of capital to compensate for an expected dead band cost. We understand that the dead band in DPCR5 was calibrated around a one per cent change in the corporation tax rates. We believe this is appropriate.
4	**Do you agree that clawback of the tax benefit of excess gearing in TPCR4 and GDPCR1 should be spread over the 8 years of the RIIO price control? If not, which alternative option do you prefer?**

[48] A change in tax costs in 2014/15 will be included in a tax return submitted by March 2016. HMRC agreement to the return and Ofgem review during 2016/17 would then allow for charges to be adjusted in time for the 2017/18 formula year. Any delay in securing HMRC or Ofgem agreement would further delay recovery in revenues.

	We agree with the proposed approach.
5	**Do you agree that clawback of the tax benefit of excess gearing should be updated every three years during the price control period?**
	We agree with the proposed approach. However, we believe the clawback mechanism needs to consider the circumstances under which it has been triggered. For example, if it has been triggered due to a network being unable to raise equity either because of the condition of the financial markets at the time, or because the allowed return is insufficient to attract equity at a reasonable cost, then it may not be appropriate to claw back the associated tax benefit.
6	**Do you agree that the tax treatment of incentives should be calculated using vanilla WACC?**
	As outlined in the response to Question 3, Chapter 2, to make retrospective changes to the regulatory regime increases regulatory risk which would need to be compensated for through the allowed return. Both DEC and BIS have issued consultations highlighting the need to avoid such retrospective changes to ensure investor confidence. For this reason, any move to change the tax treatment of incentives should only be considered for implementation on a prospective basis only. Consequently, those incentives that were triggered during TPCR3 and any triggered during TPCR4 should continue to operate on the current pre-tax basis. From a pure tax treatment perspective only, the proposal to calculate incentives using the vanilla WACC could be appropriate for new incentives with effect from the new RIIO controls. However, we believe such a change would introduce unnecessary complexity to incentive arrangements which are already very complex. Increasing complexity runs counter to Ofgem's desires to increase transparency and simplify the licence. Calculating an incremental tax allowance for the incentive scheme would prove extremely complex. The incentive mechanisms under consideration, e.g. gas entry and exit, are complex schemes to begin with. They typically incentivise National Grid to find the most efficient way to deliver additional capacity obligations. Those capacity obligations could be provided through a discrete capital investment project, through commercial arrangements, more complex investments (such as a combination of discrete projects and deep reinforcement of the network), or any combination of these. The incentives are deliberately designed not to dictate to the licensee what that efficient solution is. In this context it is impractical to model the incremental tax effects in advance as the level and nature of any expenditure will not be known. An alternative would be identify the tax impact on an ex post basis but an ex post incentive scheme would reduce the efficiency incentive on the licensee. Even if the issues above of identifying the relevant expenditure could be addressed, assumptions would have to be made on the funding of any capital expenditure. At the margin all investment is financed by debt but for larger schemes a notional equity wedge may be appropriate, in which case the costs of raising equity need to be factored in. For material investments, there may also be a need to consider the financeability of the licensee. In some circumstances the incremental tax allowance could be negative. However, a

	negative tax allowance can only be recovered if the licensee is paying tax elsewhere. This would require a consideration of the incremental incentive scheme tax flow alongside all of the other modelled tax charges. As a simplification, this issue could be addressed by ignoring negative tax numbers. The introduction of the tax trigger creates further complications. If a specific tax allowance is being calculated, that allowance should be included within the scope of the tax trigger. Consequently, all relevant incentive schemes should be included within any assessment of whether the tax trigger is activated, and incentive revenues would need to be adjusted in the event that a change in tax legislation etc does activate the trigger. The issues above would need to be addressed, and records kept (separate tax pool allocations for each investment, separate tax computations, separate funding, cash flow and debt calculations) for each and every occasion a gas entry or exit incentive was triggered. These incentives tend to flow through to revenues over multiple price control periods so the records required to be kept could grow to unmanageable levels. As a result of the complexities highlighted above, We would suggest that a pragmatic approach would be to continue to operate such incentive schemes on a pre-tax basis.
Chapter 6	
1	**Do you agree that the timing of true up adjustments for existing controls should be spread over the eight years of the RIIO price control? If not, which alternative option do you prefer?**
	Previous price controls have set the expectation that full true up adjustment for the existing controls would be delivered within the subsequent five year price control period. Consequently we believe that full true up should be delivered over the five year period following the current controls. In the case of Transmission, Ofgem have confirmed that the true-up will start in the roll-over year, 2012/13[49]. Furthermore, adjustments made in the RIIO price control for under or over recovery in previous price controls would need to be discounted at the network's cost of capital in order for the adjustment to be accurately described as true up. The use of alternative discount rates would expose customers to the risk of providing networks with windfall gains or losses on these adjustments.
2	**Do you agree that updated valuations for non-fast tracked companies should be the same as fast tracked companies, ie 31 March 2011 unless no network company is fast-tracked, in which case updated as at September 2012 in time for final proposals?**
	National Grid continues to believe that the deficit funding plan used in setting allowances should be based on the latest formal valuation. Under UK pension legislation sponsoring companies are required to provide funding to their scheme in line with the funding plan agreed as part of the formal valuation process. These

[49] "Transmission Price Control 4 – Rollover (2012/13) Scope Decision and Consultation", Ofgem, June 2010, paragraph 3.14, "*"True-up" allowances arising from deficit recovery payments during TPCR4 will therefore begin during the rollover and will take place over a number of years extending into TPCR5*."

	contributions will not be affected by any interim valuation and therefore there is no logic in basing allowances on notional interim valuations. To do so creates a risk that customers will be required to fund deficit payments based on a notional interim valuation which will not relate to the actual deficit payments being incurred by the sponsoring company.
3	**Do you agree that the deficit funding rate of return should be derived from the range of benchmarked pre-retirement real discount rates? If not, which alternative option do you prefer?**
	In order to align regulatory funding with actual deficit payments, a scheme specific discount rate should be used in determining the level of deficit funding. The scheme specific rate to be used should reflect the actual discount rate used by the scheme trustees and sponsor in determining the deficit recovery plan.
4	**Do you agree that same rate should apply to the calculation of the net present value of the ex post true up adjustments?**
	National Grid is unable to find any arguments to support the application of the scheme specific discount rate to true up adjustments, either in logic or within the consultation document. In the DPCR5[50] Final Proposals Ofgem stated that where a company funds a deficit over a shorter period than the 15 year notional period, the company would be kept revenue neutral on a net present value basis. (Paragraph 5.8, DPCR5 Final Proposals, Financial Issues document, which also defines Revenue Neutrality to mean 'the company will be paid back the cost of financing the gap'). Application of a lower discount rate to true up adjustments that did not reflect a network's actual cost of capital would be inconsistent with the approach Ofgem outlined in DPCR5, it would not keep the company revenue neutral and it would not be consistent with Pension Principle 1. Furthermore, in relation to advanced payments made into the NGUK scheme during TPCR4, the payment schedule was known by Ofgem at the time of setting TPCR4 allowances and they were agreed as part of an overall recovery plan which protected customers from being exposed to funding earlier deficit payments. To reduce the deficit funding allowance retrospectively in this case by applying an artificially low discount rate to true up adjustments would clearly be inappropriate given the efficient nature of the deficit recovery plan that was agreed and Ofgem's full knowledge of it at the time. True up adjustments for under-funding in the previous gas distribution and transmission price controls were funded using the company's cost of capital as the appropriate discount rate. To move away from this approach and apply a revised approach retrospectively to funding decisions which have already been made would represent poor regulatory practice and ultimately increase the regulatory risk

[50] "Electricity Distribution Price Control Review Final Proposals – Allowed Revenues and Financial Issues", Ofgem, December 2009, Chapter 5 Summary explained that, although focusing particularly on how they apply to the DNOs, the document set out Ofgem's decisions following their consultation on the pension principles which provide a consistent and common framework across all the network businesses that Ofgem regulate.

	premium that customers are required to fund.
5	**Do you agree that ex ante deficit funding allowances and the true up to date in a RIIO price control period should be every three years rather than truing up at the next eight-year price control?**
	We agree that deficit funding allowances should be reset every three years in line with the actual recovery plans agreed between the sponsoring employer and the scheme trustees following each triennial valuation. We agree that it makes sense that true up of actual payments against allowances should also be undertaken at that time.
6	**Do you agree that PPF levies should be part of benchmarked total costs? If not, which should be the alternative option?**
	PPF levies should not form part of benchmarked total costs since: • PPF levy and admin costs increasingly relate to non-active members. For example in the NGUK scheme active members constitute less than 5% of the total scheme membership. To include these costs within the total cost (totex) benchmark for the active membership would be manifestly misleading as it would be treating costs relating to inactive employees as part of ongoing employment costs for benchmarking purposes. In any benchmarking with Ofgem's proposed approach, an active NGUK member would attract 20 times the PPF cost that a member of a young scheme with only active members would attract. • Furthermore, the level of the PPF levy from 2012-13 onwards remains highly uncertain as the methodology for calculation is currently subject to consultation. The PPF has given limited guidance on the effect that proposed changes would have on a number of the key elements of the levy. The guidance suggests that levy costs are likely to increase significantly relative to prior years, but there is considerable uncertainty over the scale of these increases. It is not possible to provide a realistic estimate of the levy without guidance on key parameters such as the taper and the scaling factor. We note however that the PPF believe that under the new framework levy costs will more than double for 39% of all schemes in 2012/13. According to the PPF, "This is because those that would pay more under the proposal are generally schemes which pay a very low levy due to a strong D&B Failure Score." [51] Consequently, in the event that the PPF has not provided sufficient clarity to calculate the levy with accuracy by the time of the Final Proposals, National Grid would propose an appropriate ex post adjustment or pass through mechanism to protect both consumers and licensees, subject to Ofgem being satisfied that reasonable steps have been taken to manage these costs. In any case PPF levy costs and pension admin costs should be provided for through a specific allowance to reflect the fact that these costs relate to both historic pension costs and ongoing pension liabilities. The argument expressed in Section 6.30 of the Financial Issues proposals that 'a

[51] "The Pension Protection Levy: A New Framework", combined Annex p.19-20.

	doubling or tripling in the levy would not cause the network companies serious hardship' is not a legitimate basis for not allowing efficiently incurred levy costs.
7	**We invite views on whether the revised guidance to our pension principles is comprehensive and adequate for licensees and stakeholders to understand how the principles will be applied in RIIO controls and for network companies to prepare their business plan?**
	It is not apparent how the revised pension principles would be applied in all circumstances, in particular in relation to the introduction of a revised approach to funding future pension costs that arise in relation to incremental liabilities incurred following the current price controls. It is unclear how the implementation of benchmarking of ongoing costs and the allocation of deficits between established and incremental liabilities would work in practice.
Chapter 7	
1	**How should we calculate the percentage of totex allowed into RAV?**
	Paragraph 7.6 notes a number of approaches to be considered in calibrating the percentage of totex to allow in to the RAV while paragraph 7.7 suggests a preference to use a blend of all of the approaches. We believe the most appropriate approaches to be: • Treating all expenditure with an asset life of three years or less as fast money and the balance as slow money • Using network company business plan projected capitalisation rates Regulatory accounts capitalisation rates are subject to the vagaries of accounting treatments, while an average of historical capitalisation may be inappropriate if the mix of fast and slow expenditure is changing. A third consideration alluded to in paragraph 7.7 is financeability. It may be appropriate to use the totex capitalisation percentage as a tool to help ensure the overall package is financeable either on an enduring or transitional basis.
2	**The proposed totex approach includes repex, business support costs and non-operational capex as part of totex. We invite views on whether totex should include: a) Repex b) Business support costs c) Non Operational capex**
	The key driver behind adopting a totex approach is achieving an equalisation of incentives. In order to ensure that this is achieved it is appropriate that repex (making up circa 50% of our total distribution spend) should be included within this calculation. The fundamental issue on repex treatment remains ensuring an appropriate percentage is added to the RAV. We discuss this issue in our response to Question 1, Chapter 2. We also agree that business support and non operational capex costs should be included within totex. This will avoid unnecessary boundary issues between what is and is not totex, and will help to improve the equalisation of incentives.
3	**Should the definition of related parties include captive insurance companies?**

	We agree with the comments in paragraph 7.24 that captive insurance companies should be excluded from the related party clause. As acknowledged by Ofgem in paragraph 7.21, the use of captive insurance companies allows licensees to manage insurance costs in a more efficient manner. Related party margins observed in the short term are actually payments to compensate those captives for the risks they insure against.
4	**In GDPCR1 GDNs were allowed to retain the proceeds of asset disposals in RAV for five years to incentivise GDNs to dispose of assets at competitive prices. We invite views on whether this treatment should continue.**
	We agree that there should be consistency across the energy networks with regard to this treatment. On the basis that the distribution networks would arguably have had no incentive to ensure asset disposals were at competitive prices in the absence of this treatment we would recommend retaining the treatment and extending it to the other energy networks.

Impact assessment

No responses provided for National Grid Transmission.