National Grid Electricity Transmission and National Grid Gas System Operator Incentives from 1 April 2007 – National Grid response, 16th January 2007

Executive Summary

1. Our response to Ofgem's initial proposals consultation on National Grid Electricity Transmission and National Grid Gas System Operator Incentives from 1 April 2007 is structured in the following three sections:

    a) Section 1: Contains our views on the initial proposals for incentives on National Grid Electricity Transmission's (NGET's) System Operator external costs for 2007/8.

    b) Section 2: Contains the views of National Grid Gas (NTS) on the initial proposals on NGG NTS's System Operator external costs for 2007/8

    c) Section 3: Contains our views on the initial proposals relating to the internal costs for 2007/8 to 2011/12 relating to both NGET and NGG NTS.

2. Each section includes a summary of the key issues before answering the specific questions contained in the Initial Proposals document.

3. In advance of the issues raised in each section we would highlight the following key points:

    a) In **Section 1** we highlight that all of the options relating to the electricity System Operator external costs for 2007/8 are unacceptable to National Grid. We do not believe a £66m difference between the current forecast outturn for 2006/7 (£496m) and the mean cost target for 2007/8 (£430m) represents an appropriate balance between risk and reward. We would however like to make it clear that this is not a criticism of the consultation process and approach followed by Ofgem this year. We recognise that the unacceptability of the proposals has been influenced by information which has become available since Ofgem published the Initial Proposals document and Ofgem has been clear throughout the consultation process that the final proposals would be based on the latest information available before Final Proposals. We would therefore be looking for Ofgem to revise upwards the costs for next year and revise the target options accordingly, in line with the latest information available. Our response includes information on our revised forecast for 2007/8 of between £470 and £480m.

    b) In **Section 2** we highlight our broad agreement with most elements on the gas System Operator external costs for 2007/8. We are, however concerned over the proposals for gas reserve and the interaction with LNG funding. Whilst we agree in principle with Ofgem's intent to introduce competition for the provision of system reserve, it is clear that for the formula year commencing in 2007/8, this will not be in place. Hence, until this is achieved, National Grid Gas NTS, in its capacity as system operator, will rely on the LNG storage business to provide the support needed to fulfil this role and to enable us to meet our licence obligations. We therefore strongly believe that the price paid for these services will need to be set to ensure that the LNG storage business is fully funded.

c) In **Section 3** we recognise that progress has been made in relation to NGET and NGG System Operator **internal** incentives. In recognition of the progress made, we do not raise any new issues with the proposed baseline operating costs. We would, however, highlight the following two key issues:

   a. The view on baseline allowances has been reached with the expectation that the SO internal incentive framework will be supplemented by a new mechanism which will provide funding necessary for us to deliver any gas and electricity industry developments beyond those anticipated in our business plan submission.

   b. We have responded separately on the SO financial modelling used to set the overall SO revenue, including tax allowances, in initial proposals. We believe that current revenue calculations contain very significant errors including an incorrect rate of return and incorrect inputs to the tax calculation as well as a flawed depreciation methodology. These issues lead to a £68.2m difference between our view of SO revenue and that presented in Initial Proposals and must be resolved prior to final proposals.

Section 1: Electricity SO incentive schemes (External)

This section covers NGET's response to Ofgem's consultation on initial proposals for incentives on National Grid Electricity Transmission's (NGET's) System Operator (SO) External costs for 2007/08.

Summary

1. We welcome the consultation process and approach followed by Ofgem this year, which has recognised the uncertainties associated with forecasting balancing costs, given changes in wholesale prices and the impact of recent rule changes. We believe the process of updating forecasts based on the latest information available to be a helpful approach and look forward to Ofgem revising the proposals in line with the new information which has become available since Initial Proposals.

2. In line with this more flexible process of target setting, we have continued to provide revised forecasts and commentary based on the latest available information to both Ofgem and the industry. This culminated in National Grid presenting a revised forecast of £470m to £480m at an industry seminar held on the 10th January 2007[1]. We believe this more open and transparent process has given both Ofgem and the industry the opportunity to highlight any issues with the forecast prior to Final Proposals.

3. Whilst we fully recognise that Ofgem's mean cost estimate of £430m, contained in the Initial Proposals document, was based on information available at the time (and that National Grid at that moment in time was forecasting costs for 2007/08 of £458m and costs for 2006/07 of £463m), we do not believe, given the information currently available, that any of the options contained in the Initial Proposals document provide an appropriate balance of risk and reward. National Grid would be unable to accept a scheme based on a mean cost estimate of £430m which represents a £66m reduction from the forecast outturn for 2006/07. We therefore consider Ofgem should also revise upwards the costs for next year and revise the target options accordingly, in line with the latest information available.

4. Within this response we provide detail on the impact of the latest information on our forecast. Based on this information we have revised our forecast for 2007/08 upwards to between £470m and £480m (and £496m for 2006/07). We are happy to have further dialogue with both Ofgem and the industry on the detailed cost estimates in the time available before Final Proposals. Indeed, given the recent continued decline in forward wholesale prices it is likely that our forecast will also fall slightly.

5. Having mentioned the above, uncertainty will inevitably continue beyond the scheme agreement deadline of March 2007 in some cost areas, such as wholesale electricity and Frequency Response holding price. Ultimately if Ofgem's view differs from our own in the likely outcome of prices in 2007/08 for such drivers, we believe that price indexation mechanisms should be considered in order to achieve an incentive that is acceptable to both Ofgem and ourselves.

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[1] The slides presented at this seminar are available in the Operational Forum section of our website at the following address: http://www.nationalgrid.com/uk/Electricity/Balancing/operationalforum/ under '2007 Presentations'.

6. Finally, we support Ofgem's proposed wider review of incentives from 2008 onwards, to be carried out this year. There have been significant shifts in balancing costs and risks since 2004/05 and only some of which can be addressed in the time available to agree a scheme for 2007/08. Ofgem's wider review will provide the opportunity to consider these risks more broadly, in the round, and allow time to develop new potential mechanisms and frameworks that ensure clear financial incentives are applied to those costs within our control.

7. We provide our answers to Ofgem's specific questions regarding the incentive scheme proposals for 2007/08 later in this section. However these can be summarised as follows:

    a) Proposed Targets – As detailed above we believe Ofgem's central forecast of £430m is too low. This is partially due to new information not available to Ofgem at the time of publishing Initial Proposals. We, however, do not believe the lower costs associated with frequency response and constraints were justified with any evidence in the Initial Proposals document.

    b) Price Indexation – We are generally supportive of Ofgem's approach although the inclusion of indexation should not significantly reduce the scheme target. It may also be appropriate to consider the issue of price indexation in relation to frequency response. See detailed comments in response to question 8.

    c) Frequency Response and Scottish Constraint costs - Within Ofgem's initial proposals, these areas are identified as areas of possible cost reduction to levels below our forecast of £458m. However, since preparing our forecast costs in both these areas have risen above our own forecast level. We consider that Ofgem should therefore re-assess its forecast in these areas.

    d) Transmission Losses - We consider that further clarity of Ofgem's proposals is needed in this area.

    e) Balance of Risk and Reward - Overall the 'structure' of the schemes proposed by Ofgem, from low-risk to higher-risk, presents a good variety of risk options. However, clearly any of the options need to have a target cost above those contained in the Initial Proposals document.

    f) Balancing costs for 2006/07 - Since submission of our forecasts of IBC for this and next year in October, we have experienced higher than expected balancing costs in October and November. Our current projection of IBC by year-end 2006/07 is £496m, at the time of writing (mid January). Of this increase of £33m from our previous projection of £463m, £30m relates to actual costs above forecast over September October and November. A breakdown of this cost rise is contained in our response Our revised forecast for 2007/08 provides further detail how the costs seen in 2006/07 have been factored into the 2007/08 forecast.

8. In summary, we believe further dialogue is required between National Grid and Ofgem prior to Final Proposals. This should update the proposals in line with the latest information available, as per the process set out in Ofgem's consultation documents. In

this regard, it should be noted that further information on the likely costs of reserve and frequency response will become available to National Grid over the next week and therefore we would propose that any final revisions to National Grid's forecast for 2007/08 are provided to Ofgem by 28 January 2007.

9. Our detailed responses to the specific questions contained in the Initial Proposals document are contained below.

Question 1: What are your views on NGET's revised forecast of £458 million? In particular, do you consider that there are any areas where NGET is being risk disposed or risk averse in its assessment of costs? Alternatively do you consider that there are any drivers of cost that NGET has not identified?

10. We consider that the process of developing incentive proposals for 2007/08 has been open and transparent. Through this process there have been a number of opportunities to comment on our forecast assumptions, including an industry seminar on BSUoS and BSIS hosted by National Grid on 10th January 2007.

11. In developing our forecasts we have been transparent regarding continuing uncertainty, and hence risk, surrounding a number of areas of our forecast of 2007/08 costs. These include:
    - Frequency Response prices, in particular post-CAP107
    - Constraint costs
    - Wholesale Power Prices
    - Impact of the implementation of BM Start Up, replacing Warming
    - Impact of the replacement of Standing Reserve and Supplemental Standing Reserve by STOR
    - The level of 'normal' winter costs (given that the previous winter, 2005/06 is generally considered to have been unusual in terms of gas market conditions)

12. Within our October 2006 forecast of £458m, we took a generally neutral approach to the impact of these uncertain elements. We now have more up to date data on these elements and we have revised our forecast.

13. Based on the latest data our forecast of likely balancing costs is between £470m and £480m. This change reflects the downward cost pressure resulting from the continued fall in forward wholesale electricity prices offset by increases in our constraint and Frequency Response forecast, reflecting our latest experience in these areas. More detail of these changes is provided in our response to question 7.

Question 2: In this chapter we identify areas where we believe that NGET has over forecast its costs. Do you agree with our assessments? Please provide as much analytical detail as possible in your response.

14. Overall, beyond an adjustment to reflect power prices we do not agree with Ofgem's assessment that we have over forecast the likely level of balancing costs for 2007/08. We have shared our full forecast detail with Ofgem in the submission of our forecasts, and detailed summaries of our forecast have been published in previous consultation

documents. This detail provided breakdowns of the historic level of costs in each area and the reasons and assumptions behind our view of the evolution of each cost over 2007/08. Where necessary or requested, we have provided additional analysis and detail (much of which is confidential due to its commercial sensitivity) in support of our forecast.

15. We note that despite Ofgem's request in the question that parties provide as much analytical detail as possible, Ofgem has not provided any analytical detail of its own assessment of possible over forecast; therefore it is very difficult for us to comment on Ofgem's own assertion. However, we do not agree with Ofgem's assessment and have provided Ofgem with significant detail to explain our own forecasts.

16. We have been very transparent in our own forecasts and the underlying assumptions in each area. To date we have not seen any evidence of scope for cost reductions and indeed the latest data suggests that costs have increased above our own forecast expectations for constraints and Frequency Response.

17. Analysis and data are key to this process and we welcome Ofgem's request that respondents provide as much analytical detail as possible in their responses. We believe that any reductions to our own forecast proposed by Ofgem in the Final Proposals should be backed up with supporting analysis.

Question 3: Within NGET's forecast a continued area of increasing cost is mandatory frequency response costs. What do you consider to be the drivers of costs of frequency response? What impact do you consider that CAP107 will have on these costs? Do you believe there is scope for cost reductions as competition is established in the provision of these services?

18. We have provided detail on the possible drivers of the significant increase in frequency response costs post-CAP047 within our forecast, published by Ofgem in the October consultation document, Appendix 6. Our forecast assumes a slowing but continued response holding price growth through 2007/08:

    a) Our analysis has not been able to establish an underlying cost driver that can explain the price rises observed since CAP047 implementation in November 2005;
    b) Given this, National Grid shares Ofgem's concern that competition appears not to have yet emerged within the pricing of frequency response and that this lack of competition would be a strong driver of price rises;
    c) Our forecast view is that CAP107 would have only a limited impact in redistributing costs from holding prices into response energy delivery payments.

19. In line with the apparent views of a number of respondents to Ofgem's preliminary views consultation and based on the initial post-CAP107 prices, we share Ofgem's concern at an apparent lack of competition and do not consider it likely that competition will establish and lead to significant reduction in costs from their current levels. Therefore based on the data, we see no scope for the price reductions suggested in Ofgem's initial proposals. This view is backed up by the latest post-CAP107 data.

20. Any impact of CAP107 to reduce prices should be felt immediately, in January 2007 following implementation on 28th December 2006. In mid-December we received the response holding price submissions for January 2007 post-CAP107. Our initial analysis of these prices shows that any drop in holding prices is not likely to be sufficient to offset the increase in energy delivery payments. Therefore the immediate effect of CAP107 will be to increase frequency response costs; this will result in costs above our 'neutral effect' forecast.

21. Overall, it would be inappropriate to set a target assuming a cost decline when this is contrary to the evidence and latest data available. If Ofgem continue to consider that a decline in prices is likely then we suggest that consideration is given to a response holding price indexation mechanism to index a portion of our costs to the outturn response holding price. Such a mechanism would remove debate on the future trend in response holding prices from the scheme setting process and might allow a scheme to be agreed despite a difference of views in this area.

Question 4: NGET is forecasting that constraint costs will continue to be of the order of £81m. Do you consider that there is any scope for reductions in these costs?

22. We have provided Ofgem with the full detail of our constraint forecast. In the summary document the forecast was broken down by region (England and Wales, Cheviot or within-Scotland). The most significant drivers of cost are the level of transmissions outages, the distribution of generation and demand, resultant system flows and generation pricing behaviour.

23. For England and Wales and within-Scotland constraints we have provided detail to Ofgem in confidence breaking down the regional forecasts by individual constraint boundary, identifying relevant transmission system outages (or intact system constraint conditions).

24. The Cheviot boundary constraint is more complex, driven by the output of generators across Scotland. Our forecast of Cheviot costs is undertaken by a probabilistic generation and network model, and we have provided this model, and output, to Ofgem as part of our forecast.

25. Overall, our forecast is a central view of costs based on our analysis of the above drivers and represents a decline on the level of constraint costs for 2006/07. This fall in costs for 2007/08 is driven by the expected level of transmission outages in 2007/08 and an unusual level of unplanned outage constraint costs seen in England and Wales in 2006/07.

26. Ofgem has not provided any evidence or analysis to support its view of possible cost reductions. Therefore it is very difficult for us to comment further on their view and contrast it with our own forecast.

Question 5: In November a significant change was introduced to the electricity cash out arrangements (Modification P205). What is your assessment of the likely impact of this change on NGET's forecast level of costs? Please provide as much analytical detail as possible.

27. P194 and P205 were introduced on 2nd November 2005. We have not observed any major change in market behaviour as a result and therefore consider any change in costs resulting from P205 to be marginal.

28. We have previously provided Ofgem with detailed analysis of the likely impact of modification P194 (PAR 100 MWh). This concluded that the likely incentivised cost impact of this modification was of the order of £2m-£3m. The reason for such a low impact on incentivised costs is because of the effect of the Net Imbalance Adjustment (NIA) which adjusts our incentivised costs to reflect market length. Our forecast for the impact of P194 anticipated a total balancing cost impact of £13m, which would then be adjusted by £10m of NIA to give a net forecast impact on incentivised costs of between £2m and £3m.

29. P205 dampens the sharper price effect introduced by P194 by increasing the volume, the PAR volume, over which the main imbalance price is calculated from 100MWh (as proposed by P194), to 500MWh. As such, P205 will reduce the incentives on parties to balance compared to P194 and therefore we expect P205 to have a lower impact on incentivised balancing costs than P204.

30. Given that P194 was expected to impact incentivised balancing costs by £2m - £3m, our forecast anticipated that P205 would have only a marginal impact on cost and small enough to be considered 'within the noise' of our central forecast. The initial evidence post-P205 supports this view.

Question 6: Do you think that it is appropriate that we take into account the then current wholesale market conditions when setting the IBC target in the final proposals?

31. It is reasonable to take into account the most up to date information when setting a scheme target. There are a number of market uncertainties that will continue to become clearer up to the end of January 2007, ahead of the time that final proposals are set. We have taken this latest data into account within our revised forecast and we suggest that the latest information for each of these elements is taken into account when setting the IBC target in final proposals. These elements are:

    a) Wholesale market forward prices for 2007/08;
    b) Current prices for frequency response (see our reply to question 3, above);
    c) Current conditions and costs of constraints (see our reply to question 4, above, and question 7, below) seen in winter 2006/07 and the latest transmission outage plan for 2007/08, which will be finalised in January 2007;
    d) Tendered prices for Standing Reserve, now called Short Term Operating Reserve;
    e) The latest operational and cost experience of winter 2006/07, including margin costs. This element is particularly important given what are considered to have been the unusual operating conditions last winter, 2005/06.

32. With regard to power prices in particular, we would point out that all historic analysis of cost changes in relation to power price is based on a rising market, whereas the likely impact of any indexation in setting the scheme target will be against a falling market. Given the high costs seen between October 2006 and December 2006 despite a benign wholesale market, it is not clear to us that the same cost behaviour holds for both a rising and falling wholesale market.

Question 7: What do you think is an appropriate level for IBC for 2007/08?

33. We believe that the appropriate level for IBC for 2007/08 should be set on the latest data available. Based on the latest available data available, we are revising our forecasts for the current year, 2006/07 and next year, 2007/08.

34. We provided a summary of these changes at our industry seminar on BSIS/BSUoS costs held on 10th January 2007, the slides for which are available on our industry website[2].

2006/07 Projected costs

35. We have updated our previous projection of costs for 2006/07 based on the costs incurred up to December 2006 and based on the latest available data for the remainder of the year. This has led us to revise our projection upwards from £463m to £496m, based largely on above forecast costs incurred between October and December 2006. It should be noted that these cost increases have been incurred against a background of tight plant margins but also against a relatively benign wholesale market.

36. By service component, this cost rise can be broadly summarised as follows:

    a. Frequency Response: Increases due to particular circumstances during November and December and also the continued rise, above our forecast level, of prices for Ancillary Response holding under post-CAP047.
    b. Constraints: We incurred particularly heavy costs in October and November due to both price and volume drivers. These constraint actions also led to an increase in the volume, and hence the costs, of Reserve procured, see below.
    c. Operating Reserve (also known as Margin) and Energy Balancing:

        i. Since October, the system has suffered from an unusually high level of generation unavailability, notably nuclear plant. This effect does not necessarily increase the volume of Reserve holding actions in the BM, which depends on participants' FPN behaviour. However, the effect has been to move our Reserve actions on to more marginal, higher-priced generation, and this has more than offset the effect of falling power prices on Reserve prices, such that the price of Reserve actions has been slightly above our forecast.

[2] ibid

ii. In addition, the market has been more finely balanced over the October to December 2006 period which has increased the volume of Reserve actions taken by National Grid.

2007/08 Forecast costs

37. We are continuing to asses the extent to the latest data influences our forecast for 2007/08, and we will continue to provide Ofgem and the industry with our latest forecast view for 2007/08 as more data becomes available. However, in the interests of transparency we are providing this broad summary of what we assess to be the main changes to our forecast at this time.

38. At the BSIS/BSUoS Industry seminar of 10th January 2007 we indicated that our latest forecast for 2007/08 was between £470m and £480m. Since then power prices have continued to decline and it is likely that our forecast view will decline in line with this.

39. Overall, we are updating our forecast to reflect the latest data, in particular for wholesale prices, winter experience and frequency response costs and we will look to share the detail of these revisions with Ofgem and the industry in due course. In summary we anticipate the main revisions to our forecast will be driven by:

    a. Latest Power Price: Since our October forecast forward wholesale power prices for 2007/08 have continued to fall from the October annual 2007/08 figure of £43/MWh. We continue to re-assess our forecast for 2007/08 based on the latest prices;
    b. Winter experience of Operating Reserve (also known as Margin) and Energy Balancing:
        i. Our experience of Reserve volumes and price during winter 2006/07 indicates that prices do not fully track wholesale prices down in a declining market;
        ii. The balanced position of the market seen since October 2006 suggests a decline in the standard deviation of NIV. This more balanced position reduces the level of NIA correction within the forecast has had the effect of increasing our balancing costs, particularly through increasing the volume of Reserve procured;
    c. Frequency Response costs;
        i. We are reassessing our forecast of response holding prices for 2007/08, given the continued above forecast growth in response holding prices through autumn/winter 2006 and the limited initial impact of CAP107;
    d. Constraints:
        i. We are revising our constraint forecast based on the latest outage programme for 2007/08 and the latest generation output and pricing trends from autumn/winter 2006;
        ii. The main drivers of the change in forecast are:
            1. Additional planned construction work on the Cheviot boundary (former interconnector) circuits, previously scheduled for 2009 but now brought forward to 2007, reducing constraints in future years. These outages reduce the transmission capacity for the duration of the outage and lead to the need for additional

constraint actions, resulting in increased Cheviot constraint costs;
2. Updates to our generation output assumptions based on the higher than expected level of Scottish generation output seen in autumn/winter 2006, increasing both Cheviot and internal-Scotland constraint costs;
3. Reduction in the England and Wales constraint forecast based on experience of generation output and constraint risk mitigation in late 2006.

Appropriate target for 2007/08

40. We recognise that the shift in costs over the past two years does present some difficulties. Understanding both the current costs and the current trends is key to setting IBC. These issues were discussed in detail at our BSIS and BSUoS industry seminar on 10th January 2007.

41. Overall, in setting this target, it is important that Ofgem recognise:

    a. The shift in costs seen since 2004/05 and continued growth in some cost elements, such as frequency response and Scottish constraints;
    b. The fact that, for both 2005/06 and 2006/07 costs have outturned above our pre-year forecast submitted to Ofgem as part of the target setting process;
    c. A target between £470m and £480m will be lower than the outturn costs for the current year. Current year costs are currently projected at approximately £496m.

42. We will continue to revise our forecast taking account of the latest available data up until 28 January 2007. By this point we will have received the Short Term Operating Reserve tenders for 2007/08 and we will have received February 2007 generator submissions for frequency response holding prices

43. Overall, our view is that a reasonable target should reflect the latest data available. At this stage, we anticipate that this will mean a target between £470m and £480m, corrected down slightly to reflect the continued fall in power prices.

Question 8: Do you have any comments on our indexation analysis? Specifically, do you support the way in which indexation has been applied in the option we have proposed? Do you have any comments on our approaches to determining the adjustment factor? Are there any alternative approaches that we have not considered? Do you have any comments on the deadband size?

44. We have previously agreed that indexation was appropriate for incentive proposals for 2007/08. We welcome the transparency of Ofgem's detailed analysis on indexation and we agree that the proposed approach meets Ofgem's aims. However, Ofgem's indexation figures have been calculated against cost changes in a rising wholesale market, as seen from 2004/05 through to early 2006.

45. We are currently in a falling market and, based on the latest data of winter 2006/07, it is not clear the same indexation values will hold. In the period covering October to December 2006 we have seen relatively lower wholesale electricity prices without a commensurate reduction in balancing costs.

46. We believe that any indexation mechanism should reflect the uncertainty introduced by the price behaviour seen in late 2006. Indexation and the effect of wholesale prices on balancing costs should continue to be analysed with a view to inclusion of indexation in some proposed schemes, as part of a menu of possible options. Ofgem should also consider proposing different indexation levels:

    a. One at the price level suggested by Ofgem's analysis of a rising market;
    b. A second at a lower index level than Ofgem's analysis, reflecting the lower correlation seen during late 2006.

Question 9: What are your views on the four proposed options?

47. We continue to support the principle of incentivisation and we welcome the overall range of options developed by Ofgem. Relative to Ofgem's stated view of 2007/08 costs of £430m, Ofgem's four proposed options represent a good variety of possible choices. However, we do not agree with Ofgem's assessment of £430m as a reasonable central view of costs. We would expect to incur a significant loss under any of the proposed schemes and therefore none of the options would be acceptable. Our more detailed comments are as follows:

48. We consider that in setting **Option 2,** Ofgem has over-estimated the impact on the incentivised target of the price-risk band indexation mechanism relative to the no-indexation option, **Option 1**. The indexation mechanism will only have an effect for large changes in power price. The price indexation removes the risk/opportunity in both directions, therefore it is only the relative unbalance or skew of any upside/downside risk that should lead to a change in target. Ofgem should note that our mean forecast, of £458m is £6m above our central forecast of £452m. The main reason for this upwards 'skew' is due to the upwards skew in power price risk.

49. Against this analysis, a full indexation mechanism would result in a reduction of £6m in the scheme target, from £458m to £452m. Indexation with a price-risk band, which leaves National Grid exposed to the majority of likely price movement should be much less than £6m and is less important than other uncertainties. We therefore suggest that Ofgem set the target for **Option 2** to be the same as that for **Option 1** and that, given the removal of some risk of windfall gains and losses, the sharing factors under **Option 2** should be increased to be above those of **Option 1**.

50. With regard to all Options, including **Option 3** and **Option 4**, we note that these were prepared against a forecast cost a forecast cost £430m, compared to our own forecast of £458m. We would therefore expect to incur a loss under any of these schemes.

51. Given the latest data available, we expect that Ofgem will be reviewing its own forecast of £430m in due course. With regard to any target set against this revised forecast, it is important that Ofgem offer a range of targets that recognises that any remaining difference between Ofgem's view and our own view is likely to be based on the

assumptions made. With this and our support for incentives in mind we suggest that Ofgem propose at least one scheme option with a target value close to our own forecast number (albeit with different sharing factors), to ensure that an incentivised option will be open to National Grid. In addition to this, we support the continued consideration of indexation against wholesale prices and also frequency response holding prices, as indexation mechanisms for these cost uncertainties may help to close any residual gap that is driven by the assumptions of future prices.

Question 10: Do you agree with our views on IAEs going forward?

52. We agree with Ofgem's proposal to retain the current IAE framework and note the majority of consultation respondents supported this approach. We do not agree with Ofgem's proposal that, under an incentive with price indexation, National Grid would be excluded from claiming an IAE on those cost categories covered by indexation:

    a) Under an extreme circumstance that could lead to an IAE, it is unlikely that such changes in costs would necessarily be associated with changes in power price.
    b) In addition, even if the circumstance did result in a significant market move, then it is not clear that Ofgem's level of price indexation would hold under such force majeur circumstances.

53. Overall our understanding of Ofgem's indexation proposals is that these should prevent windfall gains or losses that may result from a systematic change in the market. Under many circumstances we would not expect such a shift to have led to an IAE claim under previous incentives (it did not in relation to price increases seen in 2005/06 where IAEs were raised in relation to pre-agreed areas of frequency response and Scottish constraints, not power price or un-anticipated market stress).

54. Finally, Ofgem should note that any IAE claim is subject to the determination of the Authority and as such, in the event of a claim the Authority may take into account whether the costs of any event have been suitably covered by scheme indexation.

55. Overall, therefore, IAEs should still be available for all cost areas (including indexed costs) for events that sit outside the range of normal expectations and, perhaps, previous experience

Question 11: Do you have any comments on the draft Terms of Reference for a review of the external SO incentive scheme contained in Appendix 12?

56. We support the principle of incentivisation and welcome Ofgem's proposed review of scheme arrangements. Ofgem's Terms of Reference broadly cover the relevant areas for consideration. We support consideration of longer term incentives and the possible efficiencies this may deliver. Overall, Ofgem's review should also consider:

    - the impact of Code modifications on incentive scheme parameters and costs, particularly in the case of longer term schemes, and;
    - the possible drivers of cost and market change in future years, including the impact of factors such growing wind generation on system balancing costs, as well as

those areas highlighted by Ofgem, such as offshore transmission and emerging policy directions in the European Union and/or Great Britain.

Section 2: Gas SO incentive schemes (External)

This section covers the National Grid Gas (NTS) response to Ofgem's consultation on initial proposals on NGG NTS's System Operator External costs for 2007/8.

Summary

1. In the main we believe Ofgem's Initial Proposals for the external SO costs strike a reasonable balance between risk and reward and appear to be broadly a pragmatic set of proposals for a one year scheme. There are however two particular areas of concern set out below, which in our view, would need to be addressed in the Final Proposals:

    a. the provision of gas reserve and the interaction with funding the LNG storage business; and

    b. the number of bands for the target for the gas shrinkage incentive

<u>Provision of gas reserve (Operating Margin) and the interaction with funding the LNG storage business</u>

2. Whilst we agree in principle with Ofgem's intent to introduce competition for the provision of system reserve, it is clear that for the formula year commencing in 2007/8, this will not be in place. Hence, until this is achieved, National Grid Gas NTS, in its capacity as system operator, will rely on the LNG storage business to provide the support needed to fulfil this role and to enable us to meet our licence obligations. We therefore strongly believe that the price paid for these services will need to be set to ensure that the LNG storage business is fully funded.

3. We note that Ofgem's preference is to adjust the Special Condition C3 price cap upwards, however we are concerned that we have not to date seen a firm set of proposals. From the information currently available we are not convinced that this will provide an appropriate revenue to the LNG storage business, as the income which LNG receives will clearly depend on the total volume of bookings received, whether this be Operating Margins, Scottish Independent Undertaking bookings or storage bookings (which will not be known ex-ante).

4. We believe that a more appropriate solution, to afford the LNG storage business the protection it requires until contestability is fully established, is via the provision of a revenue target. In practice, this would mean that if total income to the LNG storage business (or a subset of the facilities which Ofgem deemed to have no competition) were less than the revenue required for that business, then the shortfall would be funded by the shipper community. This could be achieved via an uplift to National Grid Gas NTS' SO maximum allowed revenue which would then result in an increase to the NTS SO Commodity charge equal to the revenue deficit of the LNG storage business. This would ensure that as a group, National Grid Gas receives an adequate revenue allowance to fund its statutory obligations.

5. In summary we believe further work is required before Final Proposals on both the appropriate form of Special Condition C3 and the numbers themselves. As it is Ofgem's intent to consider the pricing arrangements for LNG as part of the review of the gas

system reserve incentive, we believe as a matter of due process that any proposals to modify the form and/or the content of Special Condition C3 should be brought forward as part of the licence consultation surrounding the SO control.

6. Finally in the longer term or as soon as Ofgem believe competition may exist at one or more facilities, then it would be appropriate to remove the C3 price cap for those facilities. However, the issue in the meantime is that until there is full contestability, Ofgem needs to provide adequate funding for the LNG storage business to ensure that National Grid Gas NTS, in its capacity as system operator, can fulfil its obligations.

<u>Number of bands for the target for gas shrinkage incentive</u>

7. We believe that setting a variable OUG target based on the average flows through St Fergus would appear to be a sensible approach to resolve the impact of the significant uncertainty in this area. However, we are not convinced that having three discrete bands is the best approach as there is a large difference in the target between average flows being 99.9 mcm/d (7129 GWh) or being 100 mcm/d (8312 GWh). It would, in our view, be more appropriate to introduce some further bands (i.e. have 5 discrete bands) or to propose some form of sliding scale to avoid the distortion of being either one side or the other of the average flow threshold.

8. Our detailed responses to the specific questions contained in the Initial Proposals document are contained below.

Question 1: Do you agree with the proposed introduction of a new incentive to limit emissions of methane from the NTS from April 2007, and link this incentive to the prevailing price of carbon?

9. Whilst we are generally supportive of new incentive mechanisms which align the interests of National Grid with those of consumers, we are not currently persuaded that an incentive on methane emissions is appropriate for the NTS for the following reasons:

    a) Methane emissions occur through either deliberate release of gas to atmosphere ("venting") or through what are referred to as fugitive emissions. Gas emitted to atmosphere by venting comes from activities such as the operation, maintenance, commissioning and de-commissioning of pipelines and plant. Gas is vented during some maintenance activities for safety reasons. Activities such as these have been agreed with the Environment Agency and SEPA as being BAT (best available techniques) as other methods involve more energy intensive methods producing a more harmful overall level of emissions that impact the environment. Using BAT is our legal obligation, hence it does not seem necessary or appropriate to introduce any form of incentive on this activity which could lead National Grid Gas NTS to behave in direct conflict with primary legislation. It is estimated that venting operations on the NTS account for around 7370 tonnes of natural gas to the atmosphere per year.

    b) Fugitive emissions, on the other hand, come from small weeps mainly on gas control equipment and different types of fittings used. Exact leak rates from this type of equipment are difficult to establish, but it is estimated that approximately 5800 tonnes per year is emitted via this route.

c) Converting the NTS methane emissions figures into £m CO_2 equivalent could be achieved by taking the total emissions multiplying by 18 (the average increased greenhouse gas potency compared to CO_2) and multiplying this product by the present carbon price of £4/tonne of CO_2. This would give an incentive target value of around £0.95m per year. We believe such a target does not provide a particularly strong financial incentive to make improvements in these areas beyond those that would naturally be made under existing primary legislation.

10. It should also be noted that it is not just environmental legislation that drives our performance in this area. Both fugitive emissions and gas emitted from venting practices is gas which forms part of unaccounted for gas ("UAG") that is itself a component of NTS Shrinkage, which National Grid Gas NTS already has an incentive to reduce as part of the existing price control.

11. In summary we are not currently persuaded that an incentive on methane emissions is appropriate for the NTS and it may be argued a new incentive will merely create an additional cost burden for consumers without any obvious benefit. However, in the event that Ofgem decide to proceed with a scheme, we believe further work on the detail would be required before implementation.

Question 2: Do you agree that the scope for all other components should remain the same as previous years for the external gas SO incentives?

12. We believe that this seems an appropriate and pragmatic approach to take given that we are considering a scheme which will apply only for the 2007/8 formula year and Ofgem's intent to undertake a more fundamental review of the remaining years of the price control period.

Question 3: Do you agree with our proposal to vary the target for gas shrinkage on the basis of actual (2007/08) flows through St Fergus?

13. We believe that setting a variable OUG target based on the average flows through St Fergus would appear to be a sensible approach to resolve the impact of the significant uncertainty in this area. However, we are not convinced that having three discrete bands is the best approach as there is a big difference in the target between average flows being 99.9 mcm/d (7129 GWh) or being 100 mcm/d (8312 GWh). It would, in our view, be more appropriate to introduce some further bands (i.e. have 5 discrete bands) or to propose some form of sliding scale to avoid the distortion of being either one side or the other of the average flow threshold.

Question 4: Do you consider the proposed volumes for the shrinkage targets to be appropriate?

14. We believe that the level of shrinkage volume targets proposed for 2007/8 appear to be appropriate and are broadly in line with the forecasts we provided to Ofgem.

Question 5: Do you consider it is appropriate to retain the existing gas reference price methodology for the gas shrinkage incentive?

15. We believe that it is appropriate to retain the existing price methodology as we believe the logic behind setting the current scheme to be still valid.

16. The basis for the existing gas reference price methodology was put in place as part of the last price control review, but the length of the reference period was changed to the current one year period following the review of the SO incentives in February 2004. This change was felt necessary in order to avoid the possibility of National Grid influencing the cost of gas by responding to the incentive and sourcing large volumes of gas during a small time window.

17. Having mentioned the above, we believe that the review proposed for incentives applying 2008-2012 should include a review of the uplift element of the shrinkage incentive. While we believe the framework represents a good basis to set future incentives, we have seen a dramatic increase in the market cost of storage. For example the cost of Rough storage services have risen approximately 4-fold since the uplift was set. As storage competes with other means of providing swing (and hence providing for uplift) it is a reasonable indicator of the underlying cost driver.

Question 6: Do you agree with our proposed target for gas reserve, and our intention to undertake a more fundamental review of this incentive in 2007?

18. Whilst we welcome Ofgem's decision to consider as part of the fundamental review of SO incentives the issue of double provision of reserve, we believe that the proposed reduction of 39 GWh from our central case is still inappropriate for 2007/8 for the reasons set out below.

19. Ofgem has proposed a reduction of 39 GWh from National Grid Gas NTS's central case of 1589 GWh based on suggestions that:

    a. Supplies into the UK during 2007/8 will be more reliable; and
    b. Mod 006 improves Shippers ability to react to major problems more quickly.

20. In respect of the first point above National Grid Gas NTS agrees that a number of gas importation projects are likely to be commissioned during 2007/8. This should be contrasted with the expected decline in deliveries from UKCS. This means that in the absence of an extremely large demand growth it would be impossible for all supplies into the UK to be flowing at their prescribed capacity levels as there would be insufficient demand for that level of deliveries. At some entry points the presence of gas molecules may be significantly below the level implied by their capacities. It is entirely possible that during some periods certain facility types may not be flowing at all as their deliveries may be more valuable if delivered to other higher priced markets, limiting their effectiveness to act as a substitute to contracted OM services.

21. Ofgem's belief that flows will be more reliable cannot be based on any evidence of actual flows from projects that have yet to commission. Consequently, National Grid Gas NTS believes that a precautionary approach would offer greater protection for consumers by only factoring in actual experience of flow and facility reliability into any reduction of the OM volume target. Therefore National Grid Gas NTS does not agree with the basis for the 39GWh reduction proposed by Ofgem. However, there may be

more evidence from operations in 2007 that enable any improved flow or facility reliabilities to be factored into the targets for 2008/9 onwards.

22. In respect of the second of these points National Grid Gas NTS agrees that, theoretically at least, that shippers may have the ability to react more quickly than presently assumed but believes that, in the absence of further reform of emergency cashout arrangements, Shippers may not have the correct commercial incentive to adjust their flows if events serious events were to occur early in the gas day. This is because their exposure is calculated on their end of day deliveries. Therefore, National Grid Gas NTS believes it would be beneficial to review this element during 2007 in advance of setting enduring targets for 2008 onwards.

Question 7: Do you agree with our proposal to review the reference prices that apply to the gas reserve incentive? and

Question 8: Do you agree that, where market prices exceed reference prices for gas reserve, that the SO should pay these higher prices for OM gas?

23. Whilst we agree in principle with Ofgem's intent to introduce competition for the provision of system reserve, it is clear that for the formula year commencing in 2007/8, this will not be in place. Hence, until this is achieved, National Grid Gas NTS, in its capacity as system operator, will rely on the LNG storage business to provide the support needed to fulfil this role. We therefore strongly believe that the price paid for these services will need to be set to ensure that the LNG storage business is fully funded.

24. We note that Ofgem's preference is to adjust the Special Condition C3 price cap upwards, but we are not convinced that this will provide an appropriate revenue to the LNG storage business, as the income which LNG receives will clearly depend on the total volume of bookings received (which will not be known ex-ante).

25. We believe that a more appropriate solution, to afford the LNG storage business the protection it requires until contestability is fully established, is via the provision of a revenue target. In practice, this would mean that if total income to the LNG storage business were less than the revenue required for that business, then the shortfall would be funded by the shipper community. This could be achieved via an uplift to National Grid Gas NTS' SO maximum allowed revenue which would then result in an increase to the NTS SO Commodity charge equal to the revenue deficit of the LNG storage business. This would ensure that as a group, National Grid Gas receives an adequate revenue allowance to fund its statutory obligations.

26. As it is Ofgem's intent to consider the pricing arrangements for LNG as part of the review of the gas system reserve incentive, we believe that any proposals to modify Special Condition C3 should be brought forward as part of the licence consultation surrounding the SO control.

27. In the longer term, as part of the fundamental review of system operator incentive schemes, if contestability is fully established then it would be appropriate to remove the C3 price cap. However, the issue in the meantime is that until there is full contestability, Ofgem needs to provide adequate funding for the LNG storage business to ensure that National Grid Gas NTS, in its capacity as system operator, can fulfil its obligations.

28. Further information in relation to our views on the interaction between gas reserve and LNG funding is provided in Appendix 1 to this document.

Question 9: Do you agree with our initial proposals to retain the existing form of the residual gas balancing incentives?

29. We agree with Ofgem's position that the residual gas balancing incentives should be rolled over to 2007/08 in their current form.

Question 10: Do you have a view on the most appropriate form for the quality of information incentives in 2007/08? Do you consider these incentives should be revised in light of NGG's performance over winter 2007/08?

Demand Forecasting incentive

30. We agree with Ofgem that the demand forecast incentive in its current form should be rolled over to apply from 1 April 2007. However, we do not agree with Ofgem's view that "performance over the 12 months preceding to 1 April 2007 represents the best comparator for performance over 2007/08". Whilst we understand Ofgem's desire to use the most up to date information when setting the incentive benchmark, the actual forecast performance for February 2007 and March 2007 is unlikely to be reported to Ofgem until 15 days after the end of the month. We therefore believe the use of these two months in the benchmark calculation would add limited benefit whilst risking the incentive commencing without the benchmark being set. In addition, we do not believe that the summer 2006 period should be included in the base period for setting the benchmark because we believe that performance during that period was atypical for the reasons described below.

31. We believe that summer 2006 was not a typical summer as far as demand forecasting is concerned because the prolonged outage of Rough during the summer meant that it did not start injecting until mid June 2006. When Rough commenced its injection, the injection profile was much flatter than usual, hence far more predictable. This depressed the demand for the first 3 months of the summer 2006, leading to lower prices, which in return made IUK flows to Belgium higher and at a much more predictable rate. As a result, the volatility which is normally associated with storage injection and IUK was greatly reduced or absent. This had the result of significantly reducing the D-1 UNC 14:00 NTS demand forecast errors, as shown in the table below

NTS Demand Forecast Error During Summer (April - September)

	2004	2005	2006	% Change 06 on 05
Total Absolute Error (mcm)	2212.3	2259.5	1592.1	-29.5%
Total Actual Demand (mcm)	43878.0	42076.1	38870.2	-7.6%
Mean Absolute Percentage Error	5.0%	5.4%	4.1%	-23.7%

32. As can be seen from the above table, there is a large step change (24%) in NTS demand forecast error from 2005 to 2006, and we believe that the magnitude of this change is unprecedented and is primarily caused by the rare event of the prolonged

outage at Rough and therefore does not represent the typical forecast uncertainty for NTS D-1 UNC 14:00 demand forecast during summer periods.

33. One solution to this would be to use summer 2005 in the place of summer 2006 as the base for setting the benchmark. This would result in the benchmark for the demand forecasting incentive being based on the 12 months period consisting of April 2005 to September 2005, February 2006, March 2006, and October 2006 to January 2007.

34. Alternatively, it may be possible to quantify the effect of the Rough outage during summer 2006 on NTS demand forecasting and include that effect within the target. If this were possible, then the benchmark for the demand forecasting incentive could be based on the 12 months period from February 2006 to January 2007.

<u>Website Performance incentive</u>

35. We agree with Ofgem that the website performance incentive in its current form should be rolled over to apply from 1 April 2007. As for the demand forecasting incentive, we agree that a 12 month period should be used to set the benchmark, but believe that it would be of limited benefit to base the benchmark on data up to and including March 2007 given that this data will not be known with certainty until 15 days after the end of the month. We therefore suggest that the 12 month period from February 2006 through to January 2007 would be more appropriate for the benchmark.

36. Initial analysis of the performance over the February 2006 period to date indicates that the parameters within the current scheme (i.e. a 27% improvement on website availability at 20 minutes past the hour) are still appropriate.

37. The drafting within the licence currently refers to specific named reports e.g. NB92. However, at the time the incentive was originally established, it was agreed that the drafting should be changed in future to relate to specific data rather than to reports e.g. rather than stating the NB92 report (as it contains the PCLP1 forecast) state the PCLP1 forecast recognising that at the moment this is aligned with the delivery of the NB92 report.

Question 11: Do you agree with our views on IAEs going forward?

38. As outlined within our response to Ofgem's preliminary views consultation, we continue to believe that it is essential that there is an appropriate mechanism within the licence to deal with unanticipated events where there is a material departure from the anticipated level of costs which is beyond National Grid Gas NTS' control. We also detailed within our response some suggested improvements to the IAE process which we repeat below for completeness.

39. "National Grid Gas NTS would also like to suggest some potential improvements to the IAE process. Firstly, the timeframe over which IAEs can be assessed by the Authority is a maximum of three months, however, by their very nature, IAE claims can be very complex. National Grid Gas NTS believes that the period over which an IAE can be assessed should be extended. Secondly, at the present time, if the claimant disagrees with Ofgem's determination, there is no formal appeals process for IAEs. National Grid Gas NTS believes that the claimant should have the right to formally appeal an IAE

decision and this revision would ensure consistency with the appeals process presently adopted by Ofgem in relation to industry code decisions."

Question 12: Do you agree with our Initial Proposals for internal costs? and

**Question 13: Do you agree that we should implement fixed sharing factors for internal capital expenditure? If so what should the level of the sharing factors be? Should the operating expenditure sharing factors be aligned with the capex factors,
or aligned to the external incentive? and**

**Question 14: Do you think incremental internal costs associated with modifications
to commercial frameworks (e.g. UNC) should be accommodated through the existing
IAE provisions or via a more automatic cost recovery process built around enhanced
cost reporting and accountability to the industry through the existing commercial frameworks?**

40. These questions have been considered in section 3 of our response which deals with internal costs.

Views on Appendix 12 – Draft Terms of Reference for the review of SO incentives

41. We would welcome further time and discussion with Ofgem before the terms of reference are finalised. However, our initial view is that the draft terms of reference, as outlined in Appendix 12, appear to broadly cover the main points one would expect to find in a review.

42. We would suggest that the terms of reference are reviewed to take into account this winter's operational experience and any more recent modifications to the regulatory and commercial frameworks. The issue of LNG funding may also need including depending on the outcome of this consultation.

Section 3: Gas and Electricity Internal SO costs

Summary

1 We welcome the opportunity to respond to Ofgem's initial proposals on NGET and NGG System Operator internal incentives. The proposals show progress in some important areas however there are a number of issues that require development to ensure final proposals offer an appropriate balance of risk and reward and reflect agreed principles accurately.

2 We have responded separately on the SO **financial modelling** used to set the overall SO revenue, including tax allowances, in initial proposals. We believe that current revenue calculations contain very significant errors including an incorrect rate of return and incorrect inputs to the tax calculation as well as a flawed depreciation methodology. **These issues lead to a £68.2m difference between our view of SO revenue and that presented in Initial Proposals and must be resolved prior to final proposals.**

3 In respect of **baseline operating costs**, **future capital investment** and **pensions** allowances, we recognise the alignment of this work with that now concluded for TO final proposals. We accept that this work is complete, and in acknowledgement of the progress made following our response to Ofgem's preliminary views consultation, we do not raise any new issues with these proposed baseline allowances.

4 This view of baseline allowances has been reached with the expectation that the SO internal incentive framework will be supplemented by a **new mechanism** which will provide funding necessary for us to deliver any gas and electricity **industry developments** beyond those anticipated in our business plan submission.

5 In respect of **historic capital investment** we believe that the treatment of overspend against allowances for gas related investments is excessively harsh given the limited areas of NGG SO expenditure which Ofgem's consultants have classified as inefficient. Our interpretation of Ofgem's consultants' work is that any adjustment should be less than 7% rather than the 26% reduction in 2006/07 closing RAV stated in current proposals.

6 In response to Ofgem's thoughts on incentive frameworks:

(a) We favour Ofgem's proposal for NGG and NGET System Operator Incentive **sharing factors** as applied to **capital investment,** not least because of its consistency with TO capital investment incentives.

(b) We see a stronger link between **operating costs** and **external incentives parameters** and hence favour alignment of internal operating cost sharing factors with external incentives.

7 We also outline and update our thoughts over the treatment of Xoserve charges and 'TS Capex' investments.

Introduction

8 This section responds to Ofgem’s Initial Proposals for National Grid Electricity Transmission and National Grid Gas System Operator Incentives from 1 April 2007 in respect of both gas and electricity **internal** costs.

9 In the following five sections we have taken the opportunity to:

(a) outline our position on the proposed baseline allowances for operating costs, capital investments, tax and pensions and to discuss RAV rollforward and the financial modelling issues which ultimately set the regulatory allowances for the NGG and NGET system operators;

(b) respond to the proposed magnitude and application of sharing factors to over or under spends against baseline allowances under the internal incentive mechanisms;

(c) respond to and clarify points on our proposal for the management of new industry development costs;

(d) clarify our thoughts on the treatment of Xoserve charges; and

(e) re-iterate our views over the need for a ‘TS Capex’ mechanism after BETTA go-live.

Baseline Allowances and Revenue Calculations

Baseline Allowances

10 We are pleased to see that the proposed operating costs allowance for the NGET SO includes the arithmetic adjustments we highlighted as necessary in our response to the preliminary views consultation. Whilst this adjustment does not bridge the entire gap between Ofgem's preliminary views and our FBPQ submission, it does bring allowances, and the implied efficiency challenge, significantly closer to our view.

11 We are also pleased to see some movement in Ofgem's thinking on the investments required in our core Gas Operational systems. We are disappointed however in the lack of movement in allowances for future capital investment in electricity control systems.

12 We continue to differ with Ofgem and their consultants' views over the provision of gas control training facilities and real-time network simulation tools which we do not believe reflect the full costs of developing and delivering these facilities.

13 We note that proposed pensions allowances are in line with those presented in TO Final Proposals. Therefore we have no outstanding issues in the area of pensions allowances.

14 Recognising that Ofgems' proposed baseline allowances have been derived as part of the overall TPCR exercise and therefore align with the TO proposals to which we have indicated acceptance, we are not advancing new issues with the proposed allowances for operating costs, capital investment and pensions. Tax allowances and RAV rollforward issues are discussed separately.

15 However, proposed baseline allowances are only acceptable if any additional new costs triggered by necessary industry developments are managed effectively using a mechanism based on our proposal for the management of new industry development costs.

RAV Rollforward for Historic Capital Investment

16 Our response to Ofgem's Preliminary thoughts consultation detailed our general concerns over the retrospective sharing factor treatment applied to historic capital investment compared to allowances. Subsequently, we have reviewed Ofgem's consultants' reports on historic capital investment.

17 Specifically, when this methodology is applied to NGG SO historic investment, the value of these investments is reduced by 26%. We believe that this is disproportionate to the limited elements of potential inefficiency identified by Ofgem's consultants.

18 Our interpretation of the consultants' review of NGG SO historic investment is that potential inefficiencies were identified to the extent of:

(a) £3.1m associated with Ulysses simulator development;

(b) £10m within third party expenditure of which £2m can be attributed to NGG SO; and

(c) £1.5m on Ulysses Telemetry.

19 This represents 15% (£6.6m) of the NGG SO Ulysses project expenditure (£43.7m) and less than 7% of overall NGG SO investment. No other inefficiency was identified. We therefore believe that any adjustment to the NGG SO RAV should be less than 7%.

Financial Modelling

20 We are very concerned about the wholly inadequate Financial Modelling that was presented in the SO Initial Proposals. The modelling understated revenues by £68.2m which is most surprising and very disappointing. We have written separately to detail our concerns and also supplied a model which properly calculates the revenues. Given these concerns we believe it is essential that we see a corrected financial model prior to final proposals.

21 Within Ofgem's Initial Proposals, both the proposed capital investment funding and tax allowances are taken from the outputs of Ofgem's financial model. We believe that these have been calculated incorrectly and should be £36.8m higher over the five years concerned for the NGET SO and £31.4m higher for the NGG SO.

22 This understatement is due to three discrepancies:

(a) Ofgem's tax calculations are not consistent with the proposed baseline capital investment allowances and make use of a dataset we do not recognise;

(b) Ofgem's rate of return calculations use a 4.4% return rather than the correct 'Vanilla WACC' of 5.06%; and

(c) National Grid's depreciation calculations are performed using a 'straight line' calculation (which is consistent with TO treatment and ensures that the value of assets is fully depreciated at the correct rate) while Ofgem's revenue formulation uses a form of 'reducing balance' depreciation which means that assets are never fully depreciated.

23 A comparison between Ofgem's Initial Proposals and National Grid's view is shown in Tables 1 and 2 below We have provided a full copy of our model to Ofgem's financial issues team separately and expect final proposals to be in line with our analysis.

	Ofgem's Initial Proposals						National Grid's View					
£m 2004/05 Prices	2007/08	2008/09	2009/10	2010/11	2011/12	Total	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Non Incentivised Capex												
Opening Asset Value	32.2	18.4	17.8	17.3	16.7		36.4	20.8	20.2	19.5	18.9	
Total Capital Expenditure	-	-	-	-	-							
Depreciation	15.6	0.6	0.6	0.6	0.6	18	15.6	0.6	0.6	0.6	0.6	18.1
Closing Asset Value	18.4	17.8	17.3	16.7	16.2		20.8	20.2	19.5	18.9	18.3	
Return On RAV	1.1	0.8	0.8	0.7	0.7	4.1	1.4	1.0	1.0	1.0	0.9	5.4
Non Incentivised Capex Revenue	16.7	1.4	1.4	1.4	1.4	**22.3**	17.0	1.7	1.6	1.6	1.6	**23.5**
BETTA Implementation Capex												
Opening Asset Value	16.3	13.6	10.9	8.1	5.4		14.3	11.5	8.7	5.9	3.1	
Total Capital Expenditure	-	-	-	-	-							
Depreciation	2.7	2.7	2.7	2.7	2.7	13.5	2.8	2.8	2.8	2.8	2.8	13.9
Closing Asset Value	13.6	10.9	8.1	5.4	2.7		11.5	8.7	5.9	3.1	0.3	
Return On RAV	0.7	0.5	0.4	0.3	0.2	2.1	0.7	0.5	0.4	0.2	0.1	1.8
BI Capex Revenue	3.4	3.3	3.1	3	2.9	**15.7**	3.4	3.3	3.2	3.0	2.9	**15.8**
Incentivised Capex												
Opening Asset Value	43.3	48.2	48.8	50.2	50.4		43.3	47.5	46.6	45.3	42.0	
Total Capital Expenditure	11.1	7.5	8.3	7.4	6.7	**41**	11.1	7.5	8.3	7.4	6.7	**41.0**
Depreciation	6.2	6.9	7	7.2	7.2	34.5	6.9	8.5	9.5	10.7	11.8	47.4
Closing Asset Value	48.2	48.8	50.2	50.4	49.9		47.5	46.6	45.3	42.0	36.9	
Return On RAV	2	2.1	2.2	2.2	2.2	10.7	2.3	2.4	2.3	2.2	2.0	11.2
Incentivised Capex Revenue	8.2	9	9.2	9.4	9.4	**45.2**	9.2	10.8	11.9	12.9	13.8	**58.6**
Allowed Items												
Operating costs	50.9	50.1	49.1	50.3	50.1	**250.5**	50.9	50.1	49.1	50.3	50.1	**250.5**
Total Capex Revenue	28.3	13.7	13.7	13.8	13.7	**83.1**	29.7	15.8	16.7	17.6	18.2	**97.9**
Pensions Allowance	15.6	15.4	15.1	15.1	15	**76.2**	15.6	15.4	15.1	15.1	15	**76.2**
Tax Allowance	0	0	0.5	0.4	0.9	**1.7**	9.1	3.1	3.3	3.8	4.3	**23.7**
Total Internal Revenue	94.8	79.2	78.3	79.6	79.6	**411.5**	105.2	84.4	84.2	86.7	87.6	**448.3**

Table 1: NGET SO Revenue 2007/08 to 2011/12

	Ofgem's Initial Proposals						National Grid's View					
£m 2004/05 prices	2007/08	2008/09	2009/10	2010/11	2011/12	Total	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Regulatory Asset Value												
Opening Asset Value	39.8	46.9	48.5	48.1	52		40.7	39.0	34.1	29.6	32.1	
Total Capital Expenditure	12.8	8.3	6.5	10.8	10.3	**48.7**	12.8	8.3	6.5	10.8	10.3	**48.7**
Depreciation	5.7	6.7	6.9	6.9	7.4	33.6	14.5	13.2	11.0	8.3	7.5	54.5
Closing Asset Value	46.9	48.5	48.1	52	54.9		39.0	34.1	29.6	32.1	34.8	
Return On RAV	1.9	2.1	2.1	2.2	2.4	10.7	2.0	1.8	1.6	1.6	1.7	8.7
Capex Revenue	7.6	8.8	9.1	9.1	9.8	**44.3**	16.5	15.0	12.6	9.9	9.2	**63.3**
Allowed Items												
Operating costs	24.3	23.3	25.4	24.7	24.4	**122.1**	24.3	23.3	25.4	24.7	24.4	**122.1**
Capex Revenue	7.6	8.8	9.1	9.1	9.8	**44.3**	16.5	15.0	12.6	9.9	9.2	**63.3**
Pensions Allowance	6.7	6.9	6.8	7.1	7.1	**34.6**	6.7	6.9	6.8	7.1	7.1	**34.6**
Tax Allowance	0.2	0.6	0.5	1	1.1	**3.4**	5.2	4.3	3.4	1.8	1.1	**15.9**
Total Internal Revenue	38.8	39.6	41.8	41.9	42.3	**204.4**	52.7	49.6	48.2	43.5	41.9	**235.8**

Table 2 : NGG SO Revenue 2007/08 to 2011/12

Sharing Factors

24 We welcome the opportunity to comment specifically on the appropriate sharing factors applicable to NGG and NGET SO internal incentives. It is important, in our opinion, to establish a clear and shared understanding over the purpose and use of sharing factors prior to the commencement of the incentive mechanism.

25 For baseline capital investment, we see logic in making the system operator incentives consistent with the proposed TO incentives. Our understanding of how these principles would be applied to the NGG and NGET SO incentives is that:

(a) the incentive sharing factor for capital investment revenue recovery (made up of depreciation and rate of return on investment) will be set to give National Grid 25% exposure to expenditure above or below Ofgem's proposed target; and

(b) The principle of 25% exposure to deviation from target during the incentive period (2007/08 to 2011/12) will roll forward to the associated revenue recovered in the following incentive period (2012/13 onwards).

26 Our SO operating costs share common drivers with our TO operating costs (eg pay and benefits) however marginal expenditure decisions can be driven by external incentive arrangements. This could include for example:

(a) additional analysis for electricity transmission constraint management;

(b) additional analysis in the management of gas transmission capacity; and

(c) installation of control and monitoring equipment for new service providers.

27 We therefore favour the alignment of sharing factors around operating cost allowances with external incentive parameters.

New Industry Development Costs

28 The consultation asks for respondents' views on whether the costs associated with new developments should be remunerated via existing Income Adjusting Event (IAE) provisions or through a new process.

29 We **do not** believe that IAE provisions are an appropriate way to manage the costs of industry development. Whilst we support maintenance of existing IAE provisions for unforeseen events, we believe that industry development activity should be anticipated and planned for prior to the event.

30 IAE provisions fail to address this need by triggering a decision and consultation process after the event occurs rather than allowing for the co-ordinated exchange of information between National Grid and the relevant parties prior to the event. They therefore:

(a) fail to make the best use of gas and electricity industry knowledge and expertise; and

(b) fail to provide the assurance of funding required to facilitate timely and proportionate commitment of National Grid resources.

National Grid's Proposal

31 Current arrangements set allowances for a five year period meaning that the incremental costs to the system operator of new, industry sponsored developments are met either by National Grid or through specific, one off licence modifications.

32 Successful industry initiatives, such as the provision of additional Gas market information as proposed by Energywatch, can therefore have a negative impact on National Grid's performance against internal SO incentives despite delivering significant benefits to the industry. This disincentivises our positive contribution to industry development.

33 We believe that the new process we proposed in our response to the preliminary views consultation and elaborated on in subsequent correspondence provides significant benefits over existing provisions including:

(a) regular, routine reporting of the relevant costs;

(b) involvement of industry panels and use of their expertise;

(c) up front discussion of costs prior to significant expenditure; and

(d) capture of smaller but cumulatively significant developments.

34 For the avoidance of doubt, our proposed mechanism:

(a) captures the impact on NGG and NGET SO internal costs and excludes costs incurred by other agencies eg Xoserve and Elexon;

(b) is intended to remunerate the **incremental** costs associated with the change;

(c) will be subject to an annual materiality threshold on expenditure of equivalent to £0.25m for each licensed entity); and

(d) will remunerate relevant capital expenditure using a shadow RAV.

35 We also believe that cost forecasting accuracy can be incentivised and improved by basing remuneration on agreed allowances for individual developments.

36 Our proposal offers the opportunity for significant improvement in the management of industry development by:

(a) providing the means to vary allowances to meet new demands thus fully aligning the incentives upon us with industry objectives; and

(b) giving the gas and electricity industry panels and working groups the information required to:

(i) determine the scope of requirements more clearly;

(ii) make a full assessment of the cost of proposed developments; and

(iii) weigh this up against the potential benefits.

Xoserve

37 The proposed allowances for NGG SO operating costs and capital investments exclude the forecast charges levied on NGG by Xoserve. We welcome this separation of Xoserve charges and the NGG SO internal incentive arrangement as a step towards more effective management and remuneration of Xoserve's costs.

38 As such, we see a need for an explicit licence term covering Xoserve charges within the NGG SO licence drafting. We recommend that this takes the form of a single revenue term based on forecast charges reconciled against actual charges by post event adjustment.

39 We would expect this arrangement to be revised in line with any developments to Xoserve's funding arrangements that are agreed through the Distribution Price Control Review.

TS Capex

40 The NGET SO initial proposals do not make any explicit reference to the 'TS Capex' (Transmission Services Capex) investment in the Transmission networks, which is intended to manage the impact of transmission constraints on Balancing Services costs. We continue to believe an investment mechanism is required to drive Transmission Network reinforcement for the management of Balancing Services costs in line with licensees' obligations to operate economically and efficiently, in the overall interests of consumers.

41 We therefore welcome the inclusion of 'TS Capex' investment within the baseline TO Capex allowances set out in TPCR Final Proposals but also see a need to cater for requirements that develop within the next price control period as energy markets change.

42 This need is stronger than ever given the transmission constraint costs and volumes experienced after BETTA go-live and the pressures to which the transmission networks will be exposed as new generation connects at relatively remote parts of the networks. We look forward to exploring a GB wide TS Capex mechanism with Ofgem and the industry parties concerned.

Appendix 1: Interaction between Gas reserve and LNG funding

National Grid has accepted, in principle, Ofgem's final proposals for it's TO businesses[3]. Paragraph 7.58 of the final proposals included a firm proposal in respect the incorporation in to the NTS RAV of specific recent investments at LNG storage facility at Glenmavis. However, Ofgem decided that it did not wish to reincorporate all of National Grid's LNG storage assets into the NTS RAB on the basis that it did not want to create a long term funding arrangement through this route for a service provider that it believes might not be required in the future.

In paragraph 7.59 Ofgem indicated that it wished to place an obligation on NGG NTS to establish transparent and robust competitive processes for the provision of services it requires that are presently only provided by NGG LNG Storage facilities. Ofgem intends to publish the detail of this licence modification through the licence modification consultation to be held in January 2007.

Ofgem recognises that the framework it requires NGG NTS to establish referred to above will take time and has assessed the information concerning how much it costs to provide the services from NG LNG Storage that NGG NTS requires. Ofgem concludes that "*…amendments to the form of price regulation might well be justified"*. Ofgem directs the reader to its Initial Proposals Consultation for NGG NTS System Operator (SO) Incentives, published in December 2006, to provide to Ofgem their views on its intended approach. Ofgem summarises its proposal to continue with a price cap, albeit likely to be above present C3 prices, with an upward price ratchet so that OM services are always charged the higher of either that price paid by shippers for LNG storage services or the increased C3 price cap.

Crucially, no firm proposal for either the form or level of funding for our LNG Storage business is set out in the TO final proposals document. Ofgem has only proposed not to reincorporate existing LNG Storage assets into the NTS RAB and include some specific assets at Glenmavis; which NGG has accepted. However that is not to say that NGG is restricted to only considering a revised C3 price cap in deciding whether to accept Ofgem's final proposals in respect of the SO incentives package. The SO incentive package of proposals will need to be assessed including the impact on our LNG business.

National Grid Gas is concerned over Ofgem's proposals that relate to the funding of National Grid's LNG Storage business. The proposals completely ignore Ofgem's own consultants report and ignore our alternative suggestions specifically aimed to address to address Ofgem's concerns over the establishment of long term funding for some assets that may not be required in the future.

This is very disappointing given the history of this issue. In 1999 an interim price control for LNG Storage was implemented pending a fuller review ("the interim arrangements"). These interim arrangements have continued year after year for more than 7 years now despite a

[3] Transmission Price Control Review: Final Proposals, Ofgem, docuemtn reference 206/06

number of previous attempts to sort out a more enduring framework. Such interim arrangements make it difficult to make decisions on investments with long lead times due to the uncertainty of the funding framework going forward. All of our sites are Top Tier COMAH sites and hence have stringent requirements in terms of guaranteeing safe operations now and in the future and hence we take investment and maintenance decisions very seriously at these sites. The current proposals set out in the SO Price Control initial proposals merely suggest an extension of an interim year by year approach where the LNG Storage business is neither funded to finance its operations given its effective obligations to provide services, nor is given the freedom to compete and sell services if Ofgem believes the obligation referred to above is not effective. This is not acceptable.

One final opportunity remains in this price control review to put in place an appropriate funding framework for our LNG Storage business if prompt action is taken.

In this response we set out our views on the following:

- Why LNG Storage is obliged to provide (at least) services for Operating Margins ("OM");
- Can OM traditionally sourced from LNG Storage be sourced from elsewhere?
- Why Ofgem's recent proposals do not reflect our obligations and fund our LNG Storage business adequately;
- A proposal of an acceptable funding solution:
    - For the period until OM contestability arrives;
    - After contestability; and
- Treatment of closure costs

Why LNG Storage is obliged to provide services for Operating Margins

NGG believes it has an obligation created by the Gas Safety (Management) Regulations through the requirement to create and comply with a Safety Case, approved by the Health and Safety Executive, to source OM to enable NGG to meet its obligations to operate its network safely. A description of how this obligation arises is set out in Annex 1 to this response. It is important to note that Ofgem is proposing to undertake a thorough review of OM during formula year 2007/8 in order to set NGG NTS SO System Reserve incentive parameters for the period beyond 2007/8. This implies that Ofgem has acknowledged that there will definitely be a requirement to use LNG Storage to provide some of NGG's OM requirement for 2007/8.

Going forward we believe that the review of OM advocated by Ofgem will conclude that some level of OM will continue to be required. Therefore, whilst ever the obligation exists we believe Ofgem has a duty to enable NGG to finance such an obligation irrespective of where these services can be acquired. Indeed this view is backed up by Ofgem's own consultants report which saw little competition for services at Glenmavis and Avonmouth and in addition saw competition for Partington's services only arriving, if at all, at the very end of this forthcoming Price Control period.

Can OM traditionally sourced from LNG Storage be sourced from elsewhere?

NGG has stated that the implicit availability of the necessary high deliverability rates and dispersed locations of the LNG storage facilities provide ideal OM services; the existence of inappropriate C3 price caps does nothing to encourage any competition to develop. So, in the short term at least, LNG Storage appears to be the only practical service provider of OM where more localised support is required.

This is reflected by Ofgem's proposed licence obligation on NGG NTS SO to *"create a market in the provision of OM"*. Therefore, this suggests that not only does Ofgem believe an obligation exists, but that at least part of this obligation, in the short term, can only be met from services provided from LNG Storage. This is corroborated from Ofgem's own consultants' report on this matter. Hence NGG's LNG Storage business has an effective obligation to continue operations for the period that the NGG's NTS SO requires services from it. At the moment this obligation is not time limited as there is no evidence of competition forming. This effective obligation therefore requires Ofgem to provide an effective funding of the business whilst ever this is the case.

Why Ofgem's recent proposals do not reflect our obligations and fund our LNG Storage business adequately

Ofgem proposes to permit NGG LNG Storage to charge NGG NTS SO for OM services the higher of either the revised (increased) C3 price cap or an average of the prices paid for services at those facilities purchased by shippers. The LNG Storage business will only make sufficient revenue where:

- NGG NTS books the volume Ofgem assumes will be booked at C3 prices or higher; <u>and</u>
- Revenue from Shipper sales is at least equal to that assumed by Ofgem in calculating at what level to set the C3 price caps.

Any other scenario will lead to inadequate revenues to fund NGG's LNG Storage business.

For example, based on National Grid NTS's medium forecast of OM requirements, the LNG Storage business would earn £15m income if this OM volume was booked. Only if it sold all of its remaining capacity to shippers at this price would it earn income close to the amount NGG LNG Storage have indicated to Ofgem is required to fund continued effective operation at the sites.

Exposing our LNG Storage business to the price and volume volatility arising from sales to shippers and OM volumes creates the potential that it will not earn sufficient revenue to fund ongoing operations or enable decisions over long lead time investments to be made.

An acceptable funding solution

<u>For the period until OM contestability arrives</u>

NGG advocates that for the period until OM contestability is confirmed our LNG storage business be afforded the protection provided by a revenue target. Whereby, if total income to the LNG Storage business is less than a target revenue for that business then any shortfall be funded by all Shippers. This is most simply achieved through the creation of an uplift to the NTS SO maximum allowed revenue, and consequently the resulting NTS SO Commodity charge, equal to the revenue deficit of the LNG storage business. This ensures as a group NGG recovers adequate revenue to fund its effective obligations.

NGG recognises that for any discrete revenue allowance a wide range of capacity can be made available given the lumpy nature of investing in LNG Storage assets. We also recognise that Ofgem may have concerns over a possible cross subsidy between OM and storage services to shippers. Therefore, NGG proposes that the C3 price cap should be lifted for all surplus capacity sold to shippers if it is sold through an auction (Note that this has effectively been the case in previous years as Ofgem has granted annual derogations against this part of the licence condition).

If the total income from shipper, OM and SIU sales exceeds the target revenue then some of this should be passed back to consumers through a lowering of all shippers NTS SO commodity charges and the NTS SO maximum allowed revenue. This will preserve an incentive for LNG Storage to continue to make available as much capacity as economically possible beyond that required for OM purposes.

<u>After contestability develops</u>

Once contestability for OM is confirmed, both at national or local (facility specific level) the C3 price caps should be lifted completely and our LNG Storage business should compete with all other possible providers freely. This would include the removal of all access terms from section Z of the UNC. This would place LNG Storage firmly in the competitive market place where it would be free to offer access terms in accordance with section 19 (B) of the Gas Act 1986 (as amended) and governed by the general provisions of competition law. This would reflect Ofgem's confidence that the market is fully contestable.

In terms of the development of such competition we are concerned that there appears to be an implicit assumption that OM services would always be cheaper from alternative service providers to our LNG Storage facilities. This is speculation and assertion that will only be confirmed once NGG NTS issues a tender. We fully expect our LNG Storage business to play a full role in responding to such an offer to provide services on a long term basis free from undue intervention by the regulator.

We would need to identify a date for when this contestable scenario would start or at least agree a set of criteria that need to be satisfied before it could start.

Treatment of Closure costs

The revenue target approach described above would not include any closure costs in the target. We are aware that Ofgem believes that all liabilities to the consumer were removed when BG demerged LNG Storage from its main transportation business and therefore inappropriate to ask consumers to fund any closure costs.

National Grid Gas does not share this view as it is factually incorrect. The issue of who owned the LNG facilities and when is tangential to the main issue as to whether or not the LNG Storage facilities remained price controlled. In Annex 2 to this letter there is a summary of the history of the LNG Storage facilities ownership, and as can be seen from the history the LNG Storage component of the business has always been subject to price controls, either in the form of revenue caps or price caps.

Therefore, at no point has there ever been an explicit removal of LNG Storage facilities from price regulation or the main transportation business. The major change in treatment in the regulatory framework was instigated by Ofgas and not by any owner of the facilities. Consequently, the notion that consumers no longer have any responsibility for the closure costs defies logic; particularly given that these facilities remain obliged to continue to provide reserve services to ensure the safe operation of the network conveying gas to the very same consumers, and will continue to be required to do so until contestability is formed.

It is our opinion that should the LNG Storage facilities no longer be required then it is appropriate that consumers fund the closure costs given they have received the security benefits for a substantial number of years, and in the last few years at significantly discounted prices. Whilst this issue could have been solved by rolling the LNG storage business back into the RAB of NGG's transportation business at its rolled forward value (as this implicitly contained a value for the costs of closure) we note that in accepting in principle the TO final proposals has effectively closed this mechanism for the time being. However, this does not prevent NGG being allowed to recover from customers a specific amount when these liabilities become due. This could be achieved by inserting a new condition in NGG's NTS licence that is only switched on under those circumstances where closure costs need to be recovered from consumers – either through an amendment to the TO maximum allowed revenue or SO maximum allowed revenue.

Summary

In summary, we believe Ofgem has a duty to enable NGG to finance the OM obligations it faces and that, in the absence of other suitable providers, the funding level should be set so as to enable our LNG Storage business to take sensible business decisions to ensure continued safe operations and to be able to make long term investment decisions with some regulatory certainty over the mechanisms that will be applied to it. This is best achieved by setting a revenue allowance rather than a price cap for the period which Ofgem believes is non-contestable (based on the evidence presented to date by Ofgem's own consultants, this could be for the entirety of the next Price Control period for three of our facilities and at least 1-2 years for the other). If, over time, contestability in the provision of OM takes place then all regulatory encumbrances should be removed to enable the LNG Storage business to compete freely in such a market, including any OM services offered on a long term basis. Upon the removal of all regulatory constraints the closure costs associated with the facilities need to be recovered from consumers as these liabilities become due.

We recognise that the timescales for the Transmission Price Controls are now very tight and the only practical route through which our concerns may now be addressed is by including a revenue allowance in the NTS SO arrangements, as described above, until such time as contestability for OM is confirmed. We look forward to working with Ofgem to ensure we resolve this issue effectively in those SO Price Control arrangements.

<u>Annex 1</u>

Gas Act Obligations

The Authority will take into account any advice given by the HSE about any gas safety issue. This includes anything concerning gas conveyed through pipes that may affect the health and safety of members of the public. (GA part 1 4A (2) & (3))

Gas Safety (Management) Regulations (GS(M)R)

Regulation 2 (9) of the GS(M)R provides that ‘any reference in these Regulations to preventing a supply emergency is a reference to preventing a supply emergency from occurring or continuing. The guidance notes are clear that one of the GSMR’s principal aims (guidance note 2 (9) is to “….minimise the risk of a supply emergency occurring or if this is not possible to minimise its duration.” Therefore, if there is ‘potential’ for a supply emergency then appropriate action must be taken.

The definition of a supply emergency in the GS(M)R’s is an emergency endangering persons arising from a loss of pressure in a network or any part thereof. The guidance document to the GS(M)R expands this to explicitly state that this would normally be the result of insufficient pressure caused by demand exceeding supply as the result of a failure on the supply side due to an incident offshore, terminal or transmission pipeline or even incorrect forecast of short term gas consumption as well as leaks.

Regulation 3 of the GSMR requires a person conveying gas through a network to prepare a Safety Case which has to be accepted by the HSE. Any material revisions cannot be made unless accepted by the HSE. Regulation 5 requires that NGG conforms to the Safety Case and the procedures and arrangements described in it, failing which criminal proceedings for contravention may result. Schedule 1 paragraph 151 of the GSMR sets out that the holder of a safety case should identify those foreseeable events which might exist at any one time that could impact that part of the network covered by the safety case. The events described include those described in paragraph 3 above.

Safety Case Provisions

NGG’s safety case sets out those measures it will take to safely manage its gas transportation networks. This includes inter alia the provisions known as operating margins gas (“OM”) which is gas that will be used to manage system pressures in the period immediately following an unplanned event resulting in a loss of pressure in the system that arises where demands exceed supplies.

The unplanned events that OM covers reflect those set out in the guidance notes under the explanation of the definition of “supply emergency”. Essentially these are known modes of failure that if sufficient gas is held in reserve at strategic locations enables NGG to comply with paragraph 2(9) of the GSMRs i.e to minimise the occurrence and/or the duration of a gas supply emergency.

To minimise the occurrence of a supply emergency access to additional reliable short run supplies or demand reduction must be possible.

NGG's safety case includes the suite of arrangements NGG employs in order to avoid the occurrence of supply emergency (as defined in the GS(M)R). One stage in this process will be a point where NGG declares a "national gas supply emergency" i.e. the point at which NGG takes command and control of flows into its network in order to avoid the occurrence of a supply emergency defined in the GS(M)R.

Minimising the duration of a "national gas supply emergency" can be achieved by putting in place arrangements designed to delay the point at which it is declared and once declared having in place effective measures to curtail demands as quickly as possible.

Key to this is having OM available at suitable locations with providers that can achieve certain physical performance criteria at relevant times. At high system demands, but not necessarily peak, the ability of the system to lose pressure quickly is greater for any predefined mode of failure. All modes of failure will result in a supply shortage to either the network as a whole or within discrete sections of the system (if for example a pipe break or compressor failure occurs). Therefore it is crucial that service providers react quickly without fail. This gives greatest confidence to the SO that when any service is called upon it materialises; this leads to less "over procurement" to cover response uncertainty.

OM is presently provided from gas storage facilities at Hornsea, Rough and LNG storage facilities at Dynevor Arms, Avonmouth, Glenmavis and Partington as well as from a Shipper at the Isle of Grain LNG importation facility.

As can be seen there is already diversity in the provision of OM although not all facilities can substitute for each other because of some locational requirements and physical response characteristics (i.e. additional deliverability may not be available during high demand periods). This is the primary reason for the continued reliance on OM services from our LNG Storage facilities where the limited duration over which large flows can be sustained means that unused deliverability can be accessed on approximately 360 out of 365 days.

Due to the evident lack of substitutes for OM provided from LNG (certainly at the present C3 prices) LNG Storage (being part of NGG) has a duty to provide the services required by the NTS SO to safely manage its network in accordance with its safety case.

The OM requirement is sensitive to, amongst other things, the level and location of potential supplies. The expected increase in the supply margin over the coming years is forecast to result in a year on year reduction in the level of OM requirement.

Annex 2

In 1993 an MMC report under the monopoly provisions of the FTA concluded that it would be in the public interest for British Gas plc to separate its businesses to ensure that transportation and storage could be made available to all shippers without undue discrimination and to bring about self-sustaining retail competition. It recommended that British Gas plc be required to divest its trading activities by March 1997.

The Secretary of State decided that transportation and storage should be legally separated from gas supply activities within British Gas plc but did not require any divestment of ownership. (The requirement for legal separation between gas transporters and gas suppliers activities was implemented in the Gas Act 1995.) Subsequent to this British Gas plc voluntarily embarked on a demerger, resulting in the formation of BG and Centrica. Following the demerger in February 1997, BG owned Transco, which operated the former British Gas plc transport and storage activities, and Centrica owned the trading and supply operations. Transportation and storage services remained part of the regulated business of BG.

In May 1997, a further MMC report endorsed a proposal from Ofgas that BG's prices for storage should be regulated separately from its prices for transportation. As a result, BG established BG Storage as a separately managed business division of BG, but it was in the same company as Transco, so it did not have a separate legal existence.

In 1998, Ofgas carried out a review of the regulation of storage in the new circumstances. As a result, price controls on the Rough and Hornsea storage operations only were lifted in favour of a set of non-statutory informal undertakings given by BG (see paragraph 4.59). These undertakings were set to apply from May 1999 to April 2004.

In 1999 BG was restructured the purpose of which was to move all the unregulated assets out into a new company, leaving just the regulated assets behind. BG Storage was created as a seprate legal entity and the assets for Rough and Hornsea were moved into this company. The LNG Storage assets remained within Transco (now National Grid Gas).

From a regulatory perspective, both the BG Storage business and the Transco business remained covered by the single transporter licence until the restructuring of 1999, when the Rough and Hornsea assets moved beyond the reach of the licence. Hence, BG Storage formed an integral part of the regulatory accounts until 1999, even though it was separately managed.