National Grid plc Response to Transmission Price Control Review Second Consultation

Detailed response

Chapters 1- 3: Timescales, framework, context and objectives

General Comments

1 Given the number of options being consulted upon within this consultation document, which cover both price control aspects and potential reforms to the wider commercial framework, the timescales for making policy decisions by the 3rd consultation document in March appear challenging. Whilst we will aim to work with Ofgem to try and meet these timescales, developing revenue drivers which are not dependant upon the introduction of a new user commitment model would appear to be the most sensible option given user commitment models in electricity and gas exit would require implementing through changes to the commercial framework. It would seem that decoupling regulatory revenue drivers and baselines from the commercial framework would be necessary to allow the flexibility to ensure that a price control settlement could be agreed, by the end of 2006, whist allowing the optimum time to consider and introduce changes to the commercial framework.

2 In terms of objectives, we remain supportive of the broad objectives set out in the consultation document and welcome that the objectives have now been refined to make explicit reference to the requirement that the Authority has regard to the need to ensure that licensees can finance their licensed and statutory obligations.

Chapter 4 – Cost Assessment

General Comments

3 We note Ofgem's comments contained in Chapter 4 and support the need to consider the basic question of how capital expenditure allowances should be determined in order to deliver a network which is fit for purpose, ie basic compliance with standards. We would also support that the issues of network flexibility and investment to support efficient system operation should be given due consideration. As detailed in our Executive Summary, transmission networks play a key role in facilitating the competitive electricity and gas markets in Great Britain, and timely investment in the networks is essential to ensure their efficient operation.

4 The value of providing network flexibility in the transmission system should therefore be considered in the context of the wider competitive electricity and gas markets in Great Britain. We would note and agree with the risks Ofgem have identified regarding too little investment (or investment incurred too late) within Chapter 6 and the significant risks this can carry for consumers. As noted in Chapter 6, at the extreme, transmission constraints could potentially place strains on security of supply. However, a less dramatic – but very important – risk is that network constraints create unnecessary delays to new market entry, and result in higher prices for consumers.

5 On a similar theme we are aware of the large constraint costs which currently exist within Scotland and over the Anglo-Scottish border. With the likely increase in generation in those areas over the price control period it will be important to consider how investment in the network may reduce those constraints. We would therefore welcome a discussion with Ofgem on what investment may support efficient system operation.

6 In relation to the discussion contained in Chapter 4 on potential changes to SQSS, our analysis to date suggests the approach we are using is, as far as we can determine with present evidence, economic and efficient. We therefore suggest that this approach is the best basis for assessing the investments required over the forthcoming price control period

Comments on the questions where views were invited

How should the cost assessment take account of potential changes to SQSS – and in the absence of certainty as to when and how such changes might be implemented, what should Ofgem assume in estimating efficient future costs?

7 Ofgem has noted that there is work progressing, both within National Grid and elsewhere, on whether modifications to the security standards should be made in the context of increasing wind generation and what are the potential implications for the price control. Until such work is concluded, we have identified some interim policies and have sought to keep these under review with detailed statistical modelling and cost-benefit analyses. Several of these studies have been examined by Ofgem's engineering consultants (e.g. for the TIRG project) and work continues to identify criteria which can be demonstrated to be the most economic and efficient.

8 As detailed above, our analysis to date suggests the approach we are using is, as far as we can determine with present evidence, economic and efficient. We therefore suggest that this approach is the best basis for assessing the investments required over the forthcoming price control period.

How should Ofgem assess the need for additional capital expenditure allowances to provide flexibility in the availability of network capacity in advance of firm demands for capacity by network users? What, if any, reasons might there be for consumers placing a higher (or lower) value on such network flexibility over the next price control period as compared to the current (or past) price control periods?

9 As detailed in our Executive Summary, transmission networks play a key role in facilitating the competitive electricity and gas markets in Great Britain, and timely investment in the networks is essential to ensure their efficient operation. We believe that the link between timely investment in transmission networks and the efficient operation of the competitive electricity and gas markets in Great Britain is important. We therefore fully support Ofgem's view that a key focus for the review will be to develop the correct incentives for investment in gas and electricity infrastructure, ensuring they are best able to promote efficient and timely investment and allocating risk appropriately.

10 The value of providing network flexibility in the transmission system should therefore be considered in the context of the wider competitive electricity and gas markets in Great Britain. We recognise that on the one hand, zero or small allowances for flexibility might minimise the risk of consumers paying for investment which proves to be unnecessary. On the other hand, flexibility might be valuable to consumers; eg if it reduces short-term constraints, increases security of supply or facilitates increased competition in generation.

11 We believe that the issues surrounding security of supply are more of an issue for the next price control review as compared to the current (or past) price control periods. The issues surrounding security of supply relate to both the availability of energy and the availability of the network to transport the energy. This is particularly pertinent in the context of the gas market where it will be necessary to ensure that the NTS is designed and built to be sufficiently flexible to deal with the supply uncertainties associated with an increasingly diverse range of potential supplies. We would therefore support a discussion on the overall costs and benefits associated with transmission investment in the context of the wider electricity and gas markets in Great Britain.

How should allowances be set for investment to support efficient system operation, and how, in the case of electricity transmission, should interactions between NGET and SPTL and SHETL be managed in this context?

12 As detailed in paragraph 4.16 of the consultation document, Ofgem intend to focus on the robustness of the assumptions underlying load related capex proposals, areas of major uncertainty, and the potential impact of such uncertainty on capital expenditure. We believe this to be appropriate and would support an overall model whereby load related investments, that have a degree of reasonable certainty, being allowed as part of the TO price control and areas of major uncertainty being dealt with through the use of revenue drivers.

13 We explain in our response to Chapter 8 that consideration needs to be given as to the working of the revenue interaction between National Grid as GBSO and the other transmission licensees. The interaction of any new regime with the other Transmission licensees must be given careful consideration, with appropriate changes made to licences, codes and methodologies.

What areas, including those cited above and those discussed in Appendix 6, should the Authority focus on in the context of its environmental duties, in terms of analysis to support future decisions as part of the TPCR? What specific measures should be developed and implemented in respect of any such individual areas?

14 It is clear that the responsibility for environmental considerations involved in the design, maintenance and operation of the Transmissions systems should be recognised by Ofgem in their assessment of efficient investment and operation. It is, therefore, important that the regulatory framework of incentives and obligations established by Ofgem is consistent and concomitant with National Grid's environmental responsibilities and obligations. In doing this, there is a need to recognise environmental requirements both within current investment plans and as a driver for new investment, and to assess that these are efficient against both an environmental and cost criteria.

15 In addition, consideration needs to be given to mechanisms that would allow the environment and/or operating cost benefits of investment to be recognised over longer timescales than the current 5-year period in order to deliver investment that will benefit the environment in the longer term.

16 We have highlighted in our capex submission the areas where investment is required for environmental and legislative purposes, such as the Integrated Pollution Prevention and Control (IPPC) legislation in relation to emissions.

Chapter 5 – Form and structure of price controls

General Comments

17 We agree with Ofgem's views that the form of control for this TPCR should be based upon making enhancements to the basic RPI-X model to incorporate more flexible mechanisms for revenue allowances to adjust with future uncertain events (eg revenue drivers). We would also support the view that, while load related expenditure can make use of revenue drivers and other adjustment mechanisms, non load related expenditure is generally not amenable to such mechanisms.

18 We would therefore agree with Ofgem that there is still a key role for the traditional TO Price Control Review to consider non-load related revenue and also to establish a baseline for load related investment.

Comments on the questions where views were invited

How can Ofgem minimise the adverse consequences of price control re-openers if they prove to be unavoidable – even in the context of more sophisticated mechanisms for adjusting revenues automatically within the price control period?

19 Developing the form of control to provide more flexibility for revenues to adjust with changing circumstances would seem the best way to avoid re-openers. Even with a more flexible form of control it seems inevitable that there is always going to be the potential for some unforeseen events, such as changes in legislation or changes in National Grid's obligations, which may require price control re-openers.

20 A more sophisticated, flexible, mechanism for adjusting revenues should also help to minimise the materiality of a re-opener and may also provide a more suitable basis from which the impact of one-off events can be assessed.

How should the information on NGET's and National Grid NTS's performance under their current SO incentives, as set out in the report compiled by National Grid, be interpreted by Ofgem in developing an appropriate regulatory regime for these activities from 1 April 2007 onwards?

21 An appropriate regulatory incentive regime is one that aligns the interests of the SO with that of consumers. Our respective performance under the current incentive arrangements has delivered significant savings to consumers over the latest price control period. Overall, the regime has stimulated innovation, the widening of services to new providers, increasing liquidity, the introduction of new balancing products and balancing techniques.

22 With regard to NGET's and National Grid NTS's ongoing SO role, there is a continued need for incentives on the SO to respond to new challenges, delivering more efficient system operation and resulting in further savings to consumers. National Grid notes that 2006/7 marks the first year of a significant upward trend in forecast balancing costs for NGET[1]. In addition, the growth of wind generation throughout Great Britain is expected to increase the required volumes of balancing activities from 2007 onwards, placing an upward pressure on costs. The growth in wind and the challenges this will present to NGET illustrate the continued need for appropriate SO incentives to deliver savings in system operation to consumers

[1] National Grid's Forecast Balancing Costs for the financial year 2006/07 were submitted to, and published by, Ofgem on 6 January 2006/07. This details the total forecast for 2006/07 of £451.4m, a rise of £56m on the 2005/06 figure of £395m.

How might the differences between transmission and distribution, discussed above, influence the design of information quality and rolling incentives as part of the TPCR?

23 As mentioned in the Executive Summary, based on the likely inaccuracies of revenue drivers we would currently **not** support the 5 year rolling incentive mechanism contained in the consultation document, not least because such a mechanism would be unable to distinguish between variations in capex due to inefficiency and variations due to unanticipated requirements to spend. We and, as far as we can determine, Ofgem both expect such variations in unanticipated requirements to be substantial (and to be more material than for the average DNO).

How might any additional reporting arrangements (or financial incentives) in respect of environmental impacts be framed, and are such arrangements an appropriate element of the overall regulatory regime given the wider legal framework within which the transmission licensees operate?

24 National Grid already reports on various aspects of its environmental performance through channels as part of the wider legal requirements and its corporate responsibility programme. Specific additional reporting arrangements, that are deemed to be appropriate, could be included within the reporting requirements for transmission system performance identified in our respective licences. Within this, it may be appropriate to report in more detail on those aspects of environmental impact that drive our planning, maintenance and operating decisions, in particular those against which efficient investment on environmental grounds may be measured.

Chapter 6 – Price control design options - framework

General Comments

25 There are a number of high level questions contained within Chapter 6 which merit consideration before any analysis of the more detailed options set out in Chapters 7 and 8 is carried out. However at the highest level we believe it is necessary, in considering the issues contained in Chapters 6, 7 & 8, to make a clear distinction between:

(a) **Regulatory regime changes** which are likely to be necessary to ensure a price control settlement could be agreed in the required timescales; and

(b) **Commercial regime changes** in particular in relation to developing new user commitment models in gas exit and electricity.

26 It would seem that decoupling regulatory regime changes (revenue drivers and baselines) from the commercial regime changes (user commitment models) is likely to be necessary to allow the flexibility to ensure a price control settlement can be agreed, by the end of 2006, whist allowing the optimum time to consider and introduce changes to the commercial framework.

27 Although we can see some merit in the use of user commitment we would **not** advocate a model where by National Grid is **only** remunerated, during a price control period, for load related investments (above baseline) which are backed by a financial User commitment. We would therefore see investments backed up by user commitment being a sufficient, rather than a sufficient and necessary, trigger for investment. Given this, a revenue mechanism other than user commitment needs to be agreed for investments that are driven by the requirements of our broader licence obligations. Revenue drivers may therefore need to be linked to an output measure such as additional capacity released or additional km of pipes or wires rather than purely to the existence of a user commitment. Such a model, when considered in conjunction with the overall concept of the revenue drivers acting as effectively a "down payment" for necessary investment during the price control period - which would be adjusted as part of the next price control such that the transmission company was left whole - would seem the best way of dealing with the uncertainties over the price control period.

28 In relation to the commercial regime and the development of user commitment models it would seem that the fundamental questions are:

(a) what should the user commitment apply to (all capacity or incremental capacity); and

(b) whether the commitment is provided for both entry and exit or just entry.

29 In assessing these questions (and any other proposed changes to the existing regimes) a clear assessment should be undertaken to understand the costs and benefits of moving from the status quo positions. Our initial view would be the costs and benefits associated with obtaining user commitment for **all** capacity, in the context of electricity entry, appears to have merit given the current issues associated with the GB queue, whilst the **current** case for such a regime in exit (particularly electricity exit) appears less clear.

Comments on the questions where views were invited

Whether respondents agree that Ofgem's focus on 'user commitment' options is appropriate, or whether they consider that there are other traditional price control options (or de-regulated revenue options) that might better meet Ofgem's objectives for the TPCR, particularly in the context of the Authority's statutory and other legal duties?

30 We have answered this question in the following two parts:

(a) Part 1 examines two interpretations of Ofgem's descriptions of a user commitment model and in particular considers the link to revenues; and

(b) Part 2 examines the two questions raised in the section above in relation to what the user commitment should apply to:

Part 1 – two interpretations of Ofgem's user commitment model and how it drives network revenue

31 We outline below two interpretations of Ofgem's description of a user commitment revenue remuneration model based on descriptions within the consultation document.

Option 1 - Changes to revenue driven solely from user commitments

32 Under this option a set of revenue drivers would be defined where it was a **necessary and sufficient** condition that a user commitment is made to back up any increase in revenue and hence by definition, investment would only be made if such a user commitment was made. In the extreme, this model would require user commitments from both existing and new users of the networks and apply both to the entry and exit sides of the market. Hence all players would make commitments of their longer term use of the network.

33 In this model, from both the transmission company's and the user's perspective, the user's commitment would be critical in terms of determining what investments are undertaken and also when capacity is made available.

34 Our assumption is that in this model, to ensure clarity of obligations, there would be a change to the broader transmission licence obligations with regard to 1 in 20 peak day network requirement on the gas side and the security standards on the electricity side. These changes would reflect that the transmission network would no longer forecast on its own likely input or offtake parameters to ensure compliance but instead would use solely user forecasts for these variables to inform its planning.

Option 2 - Revenue driver based on User Commitment is only one element of how revenues could be adjusted

35 This option would determine a revenue driver for that part of the market where it is deemed sensible to construct a long term user commitment and one which can easily be translated into a revenue driver.

36 Additionally, this option would therefore explicitly acknowledge that there would be potentially other drivers which could result in additional transmission investment and hence would require other methods to be determined to remunerate them. It is therefore assumed that it will not necessarily require changes to the security standards on the gas and electricity networks.

37 This option therefore covers a variety of potential outcomes. For example, if applied to gas exit, the revenue driver could either cover the vast majority of incremental

investment requirements if it is assumed that the 1 in 20 demand signals arrive through the products defined in the commercial regime or a lesser amount if it is decided that these signals will not necessarily appear from the commercial products and hence we may be required to undertake investments to meet the wider 1 in 20 obligation.

38 To cover other capacity related investments, not covered by user commitment, an additional mechanism could be used. This could take the form of an application to release to Ofgem (akin to the current Incremental Entry Capacity release process) or be a more explicit income re-opener such as akin to the Transmission Investment for Renewable Generation (TIRG)

Assessment of the Options

39 There are a number of reasons why we believe Option 1 as defined is **not** practicable, as there are a number of reasons why the market may not be able to signal their requirements in a timely and accurate manner:

(a) Some capacity increases will be triggered by a combination of user requests and an assessment of when these will occur. Hence the timing of the long term capacity requests is crucial. If all the potential requests in a particular location do not come at the same time, there is a danger that inefficiencies will occur if each individual market signal is looked at in isolation. For example, if one market player has signalled the need for a extension of the NTS for a particular volume, does the transmission owner build just for that volume or try to anticipate what the future use will be? If the known signal is all that is relied upon and one year later another party requests capacity, then it is likely that duplicate pipe routes would have to be developed. This highlights the issue that transmission investments are large projects and hence it is desirable that they are sized appropriately to minimise disruption particularly to the environment. Another example would be the difficulty of determining the appropriate investment to cater for new renewable projects given these are small individually but can create large requests as a group. As these projects are at different stages of their planning cycle, it is not clear that a combined market signal would be secured at the same time.

(b) The market rule may not work perfectly in terms of incentivising a long term signal. For example, despite their clear intent, the gas entry capacity regime has not always driven long term signals being received. In fact, through elements of its design, it potentially incentivises short term bookings if users perceive no competition for capacity. The user will only commit if there is a threat of competition or the sole user wants more capacity. This is a particularly pertinent issue in considering developments of user commitment models on gas exit and electricity given lack of competition at a node.

(c) Some users may not be in a position to financially commit to long term capacity bookings at the time in which that signal is required. For example, it is our experience that a number of players only achieve financial close at the point at which they have all elements of the project in place and hence banks may not be willing to make commitments to transmission capacity if other elements are not in place. This can lead to a delay in when the market signal is placed.

(d) In certain cases other market rules may determine that the user does not have to make a market signal. For example, the BETTA transitional rules mean that not all users face the same commitments in terms of making capacity requests.

40 We therefore support Option 2 (User commitment is sufficient but not necessary for revenues to adjust) which is a model that recognises that revenues should **not** be determined **solely from user commitments** due to both practical limitations of revenue drivers and also the need for investments to meet wider obligations.

41 We believe that developing revenue drivers which are not dependent upon the introduction of a new user commitment model would appear to be the only sensible option given user commitment models in electricity and gas exit would still require implementing through changes to the commercial framework. This implies that a revenue mechanism other than just those driven by user commitments needs to be agreed for investments that are driven by the requirements of our broader licence obligations

42 Revenue drivers may therefore need to be linked to an output measure such as additional capacity released or additional km of pipes or wires installed rather than purely to the existence of a user commitment.

Part 2 – To what should user commitment apply?

All capacity or only incremental capacity?

43 In principle, user commitment could be required only for incremental capacity or could apply to all capacity. Thus:

(a) **All capacity.** All users, whether existing or prospective would be required to indicate their capacity requirements long term via the same mechanism. We believe this is the model which Ofgem are describing in their consultation document. It could be said that this was the principle that was designed to underpin the current Gas Entry capacity regime. However, due to the obligation to release baseline levels in all timescales irrelevant of user commitment and the obligation to release capacity short term at potentially zero cost, this principle has not been seen in practice as a number of parties only give very short term indications of their intentions.

(b) **Incremental capacity only.** In this interpretation, all users who wished additional capacity from that available on an existing basis would be required to make a user commitment via the same mechanism. It would be assumed that existing capacity holders would retain their capacity holdings unless they had given notice that they would relinquish them.

This could be described as the principle underlying the existing electricity entry access regime and the existing transitional gas exit regime. All users who wish additional Transmission Entry Capacity or additional gas exit capacity must indicate their requirement and provide some form of financial commitment for the provision of that capacity. On the transitional gas exit regime, there is not however a completely common framework to provide this but the principle is the same. Given the comments above regarding the practical reality of the gas entry regime, this could also be seem as how the gas entry regime has worked in practice at the majority of terminals, i.e. requirement to commit via a homogeneous mechanism for incremental capacity.

Entry, exit or both?

44 User commitment could apply to both entry and exit or to one of these alone. For example, there is no explicit capacity product on the exit side of the electricity transmission system. However long term commitment is sought during construction from both Distribution and Directly Connected customers who wish to increase capacity at their connection points.

Assessment of the options

45 We recognise the benefit of a regime in which all users would indicate their total capacity requirements through a long term commitment (i.e. an Option 1 approach). We note that this would imply a significant change in the electricity and gas exit access regimes and hence a cost benefit exercise needs to be undertaken to assess the benefits of increased information for investment planning against the implementation costs and ease of implementation of this option.

46 In particular with regard to gas exit, we believe that it will be important to identify what elements of the extant regime require reform rather than starting from the model developed as part of Network Sales. We believe the key issues that require redress are the need for a common capacity booking process for all exit users, the need for clarity on the user commitment required by those users for incremental capacity requests, the definition of consistent products between Direct Connects and DNs (whether that be two separate products or a single capacity product) and the need for a short term release mechanism. We therefore believe the additional step of considering a change where all users have to book their total capacity requirements in advance, which we believe conceptually is a better approach, will need cost benefit assessment against any revised incremental only regime (assuming the above amendments are made).

47 On electricity, the status quo is a common process based on first come first served applicable to incremental capacity requests only (i.e. an option 2 approach). This process has come under severe pressure from the large numbers of application brought about by the significant interest in new renewable power projects and the BETTA transitional arrangements. An Option 1 approach could aid this pressure in terms of requiring all users both new and existing to commit long term to capacity such that more precise requirements could be identified. However, developments of the option 2 regime could be looked into to provide different forms of financial commitment perhaps relating to a commitment to fund a number of years capacity charges. In addition, a booking window could be considered to avoid the first come first served basis.

48 We believe any User commitment should be clearly non-discriminatory and transparent. We would therefore support a simple methodology published ex-ante, as per the length of booking signal in the current entry regime rather than the less transparent approach being proposed for the transitional gas exit arrangements.

49 We note that the length of commitment and its relation to investment lead times is a key factor in determining the implications of a full user commitment model.

What is the appropriate allocation of investment risk between network users (both generally and at specific locations), transmission companies, and consumers, during the different phases of investment development, e.g. planning and design, construction, and operation?

50 We do not believe that network companies should be financially exposed to risks beyond their control. Hence we believe that any commercial or regulatory regime surrounding the provision of new capacity should recognise the risks that are beyond the transmission company's control.

51 Given the current high potential cost of capacity buybacks, in the event that investments cannot provide capacity in the timescales required, and such costs maybe beyond the control of the transmission company, there is a strong case for not placing such costs with the transmission company or other customers or consumers.

It is for consideration whether the consent risks for individual projects should more appropriately lie with the connecting party, as is the case in the electricity regime.

52 We would support reform of the current gas entry regime to ensure that fixed time periods to provide capacity are accompanied by either more appropriate compensation if the capacity is late (separate buyback pot or compensation rate) or explicit recognition in the timing of capacity provision that this is subject to consenting delays or delays beyond the transmission companies control. The current gas exit and electricity regimes provide some useful features within them which could be used to consider reform of the gas entry regime.

53 In the event that incentives were put in place on the timescales associated with delivering new capacity we believe that it would be necessary to review the default timescales for delivery, given the increased environmental legislation. In addition if Ofgem is planning to impose significant downside risk on transmission operators for under-performance, then there needs to be a comparable upside and/or a higher base rate of return.

Whether it is appropriate to seek to separate, both formally and operationally, the issue of how charging and reserve prices are set at gas entry from the issue of how incremental revenues are determined under the price control?

54 As a pragmatic measure we support de-coupling of revenue drivers from reserve prices or tariffs for capacity provision

55 Given the potential fundamental commercial regime changes implied by user commitment, we believe the two features above are necessary to allow the flexibility to ensure a Price Control settlement could be agreed whilst allowing the optimum time to consider and introduce changes to the commercial framework.

56 In addition there are a number of specific challenges in terms of defining a workable user commitment regime with appropriate incentives on multiple electricity Transmission Owners given the GBSO is the one who is receiving the user commitments. This again suggests some de-coupling is an appropriate approach.

57 Another potential advantage of decoupling the revenue aspects of the regime from the charging aspects is that it would enable Ofgem to lead on the price control elements whilst National Grid could take forward industry consultation on charging developments (without those developments directly impacting on National Grid's regulated revenue). Ofgem will be aware that we have already set up a Gas Charging Methodologies Forum where we would hope to develop proposals for any amendments to charges (and auction prices) in consultation with the industry. This review will encompass gas entry reserve and incremental prices, gas exit capacity charges and any consequent changes to Commodity Charges. We have also requested users to provide any areas of the charging methodology they wish to see developed. The consideration of capacity related charges will include consideration of the Transcost algorithm and whether there is a better method for determining the long run marginal cost of capacity on the gas network. This will include comparison with our LRMC model on the electricity network.

Chapter 7 – Incentive Options - Gas

General Comments

58 We welcome Ofgem's comments contained in Chapter 7 that the key purpose of the price control is to ensure there is sufficient remuneration to meet obligations and to ensure that there are appropriate financial incentives to do so efficiently. The paragraphs below highlight the key issues in relation to **obligations** and **remuneration**.

59 As mentioned in the Executive Summary, we require clarity on our **obligations** within the gas market particularly in the context of user commitment models. We would support the wording in Chapter 7 (paragraph 7.13) which states that the NTS should take into account user commitment **and all other relevant information**. As recognised in our Executive summary a model based purely on user commitments may lead to under investment in the NTS, which may be to the detriment of consumers. Ofgem's Impact Assessment in UNC mod 0049 recognised that even minor disruptions in the availability of desired system capability can be extremely costly.

60 Although clarity is required in relation to the existing gas entry model, it is even more crucial in the context of adopting a user commitment model in gas exit. In relation to gas exit the NTS currently has a 1 in 20 obligation which also forms part of the Safety case. We are therefore obliged, either with or without any user commitment, to plan the network to be compliant with our 1 in 20 obligation. It is necessary to be clear how National Grid would be remunerated for investing to meet the 1 in 20 obligation if that was **not** supported by any user commitment.

61 In terms of **remuneration**, it will be necessary to agree as part of the price control process how much revenue will be allowed as part of the price control process (TO allowance) and what mechanism is used to remunerate the NTS for incremental outputs not foreseen at the time the price control was set. With this mind we could envisage a model whereby the TO allowance is based on a reasonable assessment of meeting the 1 in 20 obligations including any Directly Connected loads (eg power stations) which have signed an ARCA. The revenue driver would then be used to reflect any additional outputs above this baseline level of capacity.

62 In terms of the commercial framework the key question is whether a similar user commitment model to that which exists in relation to gas entry should be extended into gas exit. As mentioned in our response to Chapter 6, a clear assessment should be undertaken to understand the costs and benefits of moving from the status quo positions. As part of this process it may need to be recognised that it may not be possible to meet all the objectives and in certain areas pragmatic decisions may be required. First and foremost, it is important to identify what elements of the extant regime require reform rather than starting from the model developed as part of Network Sales. We believe this work should be undertaken in advance of considering the relative costs and benefits of obtaining user commitment for all capacity as against the transitional requirements of user commitment for incremental capacity.

63 We would endeavour to bring forward some strawman proposals to illustrate the differences between a full user commitment model against an incremental only approach to Ofgem's Exit Development Groups which would aid the industry in progressing such a cost benefit assessment.

64 On a separate note we would welcome further discussion on the allocation of risk between users and network companies. We provide our initial views in this area in responding to the questions relating to buy-back incentives. At the highest level, however we would make the following comments:

(a) Any commercial or regulatory regime surrounding the provision of new capacity needs to recognise the risks that are beyond the transmission company's control. Environment consents are an increasingly important element in this context.

(b) If Ofgem is planning to impose significant downside risk on transmission operators for under-performance, then there needs to be a comparable upside and/or a higher base rate of return.

Comments on the questions where views were invited

65 The following section provides answers to the questions posed in the Views Invited section at the end of Chapter 7.

Revenue drivers for entry and offtake

(a) ***Should the revenue driver be entry point specific, zonal/locational or global? What are the advantages and disadvantages of these different options – and to what extent do these advantages and disadvantages differ between entry and offtake? If a zonal approach is preferred, then how might zones be defined?***

66 At present it is difficult to express a definitive preference on the different models contained within the consultation document both for gas entry and offtake. In particular the enduring regime for gas offtake is extremely fluid at the moment with a wide range of industry views on the appropriate way forward. We are happy to work with Ofgem, utilising system modelling where appropriate, to help determine which model will best meet the price control objectives. It is important, however, that the model should allow the flexibility to ensure a Price Control settlement could be agreed whilst allowing the optimum time to consider and introduce changes to the commercial framework.

67 In advance of undertaking more detailed work we have set out below our initial thoughts on what are likely to be the important matters of principle to National Grid. The key regulatory principles are detailed below:

- If we respond to market signals we should be remunerated.
- We would support the decoupling of regulatory revenue drivers and baselines from the commercial framework.
- Any baselines which create obligations should not exceed system capability. We are aware from the current price control if baselines are set above the level of network capability, this can remove the incentive for users to signal their true needs in any long-term booking process and hence lead to the situation where the network operator cannot respond in a timely manner to any signals for additional capacity being signalled in the shorter term. It can also lead to necessary investments not being properly remunerated.

68 However, as to the approach to defining the appropriate zones, some high level principles can be determined. The determination of the zones should:

- reduce the chance of sterilised capacity;
- be set on the basis of a high degree of substitutability between nodes; and
- be robust to different supply/demand scenarios and to future changes on the network (where possible).

(b) ***What are the key cost drivers of incremental capacity – and how might these vary between entry and offtake? How should these be quantified?***

69 In general the cost drivers for incremental capacity on the system will be the same for both entry and exit; it broadly depends upon whether investment is needed (given an assumed level of supply and demand) and the nature of that investment (new pipelines or compressors). The high level cost drivers for each of these different types of investment are:

For pipelines:

- the length and diameter of the pipeline to be constructed
- the levels of steel prices (this implies that the revenue driver should be indexed)
- the terrain that the pipeline is routed through
- time to construct the pipeline (costs may increase if timescales are accelerated)

For compressors:

- whether on a new ('greenfield') or existing site
- the size of compressor

70 In addition to the above, it should be noted that changes to the supply and demand patterns can alter the amount and therefore cost of investment in a specific area. All these factors should be taken into account in developing a revenue driver, either implicitly or explicitly.

(c) ***Should revenue drivers be fixed for the price control period or should they be adjusted during the price control period?***

71 In theory it is possible to go for either of the options described (fixed or adjusted revenue drivers). Our experience to date, however, would suggest that fixing revenue drivers for a fixed period brings with it a significant risk that the revenue drivers may become unreflective of investment costs, particularly towards the end of the price control period. This has been shown to be the case in the current entry regime where significant changes in the pattern of supply and demand and increases in construction prices have led to UCA's becoming unreflective of costs.

72 Clearly the issue associated with construction prices could be addressed by indexing the revenue driver by the relevant construction index. The issue associated with changes in supply and demand patterns impacting on investment costs is however more difficult to solve. We would therefore advocate either the revenue drivers being adjusted during the price control period or effectively treating the revenue received from revenue drivers as being a 'down payment' for necessary investments during the price control period (as suggested in our response for electricity). In the event that the revenue drivers have provided insufficient remuneration (or too much) this would be adjusted as part of the next price control such that the transmission company was left whole.

Entry capacity baselines

(d) ***Should the baseline be a measure of capacity and if so, should it reflect the level of existing capacity or the level of anticipated capacity?***

73 We believe that capacity is probably the correct measure for the baselines as this is the product which is made available to users. However, as to whether the baselines are set commensurate with the existing capacity or an anticipated level of capacity needs to be linked back to the assumptions made underpining the allowance within the TO price control. However, we believe that it is important that the level of the baselines should be set to reflect the physical capability of the system taking account of the interaction which exists between the different entry points.

74 On balance we would support a model whereby investments with a large degree of certainty, for example those backed up by some form of user commitment, being allowed for in the TO price control with the baselines being adjusted accordingly.

(e) ***For revenue restriction purposes should the baseline be set 'flat' for the five years of the price control period or should it incorporate growth (or decline)?***

75 Baselines should be set to be aligned with the allowance made within the TO control (i.e. if growth is assumed within the TO control then the baselines should reflect it, if not then baselines should be set flat). In relation to the alternative options, we believe that a model that remunerates investment with a large degree of certainty within the main TO allowance, to be the most appropriate model.

(f) ***Should the baseline be set on an entry point specific or network wide basis or should no ex ante baseline be defined? What are the advantages and disadvantages of the different options?***

76 Further work is required on the nodal, zonal and global revenue driver models. If Ofgem were to follow a zonal baselines / revenue driver model, it would be necessary to address how National Grid is remunerated for relatively large increments at individual nodes (eg new power stations in relation to gas exit). In addition, any zonal model should aim to:

- reduce the chance of sterilised capacity;
- be set on the basis of a high degree of substitutability between nodes; and
- be robust to different supply/demand scenarios and to future changes on the network (where possible).

Approaches to offtake reform

(g) ***Do you believe that Ofgem's proposals for a long term user commitment model are appropriate?***

and

(h) ***Are there any alternative models, including those which could be characterised as variants of the status quo that would meet the defined objectives?***

77 We believe that it will be important to identify what elements of the extant regime require reform rather than starting from the model developed as part of Network Sales. We believe the key issues that require redress are the need for a common capacity booking process for all NTS exit users, the need for clarity on the level of commitment required by those users requesting incremental capacity, the definition of

common products between Direct Connects and DNs (whether that be two separate products or a single capacity product) and the need for both a long term and short term release mechanism. We therefore believe the additional step of considering a change where all users have to book their total capacity requirements in advance, which we believe conceptually is a better approach, will need cost benefit assessment against any alternative simplified regime (assuming the above amendments are made).

78 We will endeavour to bring forward some strawman proposals to illustrate the differences between "financially firm user commitment models" and simplified approaches to Ofgem's Exit Development Groups which would aid the industry in progressing such a cost benefit assessment. Our initial thoughts on how the regime may be simplified are set out below.

Seeking to simplify the proposed regime

User commitment model

79 We believe it may be worthwhile considering whether there are less complicated approaches that might be used to deliver longer term signals in respect of the "unconstrained" longer term booking regime.

80 In practice changes in capacity requirements will arise from DNs because of connected demand variations (and potentially from the extent to which they may wish to change their offtake flow variation patterns) and from TCCs where they expect to change their requirements (which might be expected to be far less frequent than DNs) or where there is new load wanting to connect.

81 To avoid the risk of stranded investment there may be a requirement for existing users to signal their capacity utilisation sufficiently far ahead that it mitigates against the risk of inefficient, unwarranted investment.

82 It may therefore be that the benefits of a "financially firm rights model" can be delivered by a regime that features requirements for both (new and existing) users to:

- indicate incremental capacity requirements above existing entitlements and to commit via a financial commitment to pay for such capacity for a period of "n" years; and

- Indicate any reduction in capacity requirements given a notice period of "m years" before any reduced liability to pay for capacity becomes effective.

83 The "n" and the "m" are parameters for the regime that will determine the risk sharing between individual consumers and the generality of consumers.

84 We believe that this approach may be implemented as a relatively simple overlay over and above current offtake registration processes and therefore may afford considerable scope to simplify the regime from the perspective of many market participants. However, we anticipate that even such a simplified approach would involve significant industry development and changes to the commercial regime and supporting IT systems.

Product definition

85 We remain of the view that there are considerable merits in retaining a nodal product definition and that the DN should pay for NTS Exit capacity products.

86 We now have experience of both operating the “flat” and “flexibility” regime and DNs’ NTS Exit capacity incentive. Based on this experience we have articulated some alternative options to the Enduring Offtake Working Group (EOWG).

87 We believe that there may be merit in contemplating either refinements to the two product model or a one product model. This affords an ability to simplify the user requirement assessment process, application and NTS investment interpretation processes whilst retaining the concept of some limitation on the extent of offtake flow variation via a daily assessment of “flexibility utilisation”. Alternatively it might be appropriate to consider having potentially different products applying to different classes of users, such as DNs, Direct Connect offtakes and bi-directional connections.

88 We are happy to work with Ofgem and the industry to provide information to inform these approaches that could be included in the next Ofgem Price Control document.

Allocation processes

89 The model developed during Network Sales envisaged longer term application and allocation processes based upon the Gas Entry model. Given the limited extent of competition at each NTS offtake and the number of offtakes the complexity associated with these arrangements might not be warranted.

90 It is possible that many of the benefits arising from improved signals and financial commitment could be achieved by the use of a single (LRMC) based price to determine the financial commitment that might underpin incremental capacity allocations. At first sight this might appear to be a considerable simplification that might materially affect the effectiveness of the regime, particularly when compared with the sophisticated price step approach used at entry. However, in the context of exit, such accuracy may be spurious particularly in the light of requirements to adjust charges (either by scaling or via alternative adjustment mechanisms) to meet allowed revenue objectives.

91 In the short term we recognise that some price rationing may be appropriate if demand exceeds supply. Such release may be essential to ensure that all available capacity can be accessed and that we satisfy EU Regulation requirements.

Offtake product definition and baselines

(i) ***Which of the options defined for product definition and baseline determination do you believe is most appropriate?***

92 As a general principle, we believe that there is considerable merit in a location specific (nodal) product definition. Given the nature of transportation service provision, we believe that uncertainties as to precisely where capacity is required (as may arise under a zonal product definition), could generate a material increase in the risk of inefficiency in respect of infrastructure requirements and possibly operational costs. In relation to the most appropriate determination of baselines we would refer you to the answer to question (a) relating to entry baselines.

(j) ***Are there any alternative models that would meet the defined objectives? E.g. a nodal model without the substitution incentive or a “no baseline” option***

93 As detailed in our response to question (a) it is difficult at present to express a definitive preference on the different models. In particular the enduring regime for gas offtake is extremely fluid at the moment with a wide range of industry views on the appropriate way forward. Once the basic enduring commercial framework is understood we would be happy to work with Ofgem, utilising system modelling where appropriate, to help determine which model will best meet the price control objectives.

(k) ***Should the baselines be fixed for the five year period, or increase over time?***

94 As detailed in our response to question (e) baselines should be set to be aligned with the allowance made within the TO control (i.e. if growth is assumed within the TO control then the baselines should reflect it, if not then baselines should be set flat). On balance we believe a model whereby the TO allowance is based on a reasonable assessment of meeting the 1 in 20 obligations, including any Directly Connected loads (eg power stations) which have signed an ARCA, and revenue drivers then being used to reflect any additional outputs above this baseline level of capacity, to be the most appropriate model.

(l) ***What method of determination of baseline levels (as discussed in Appendix 7 is most appropriate for the determination of the level of exit baselines?***

95 Within Appendix 7, five main ways to define the level of baseline capacity are outlined. For exit, the most sensible way to set baselines would be to base them on the assessments of existing and/or future demands on the network as proxied by the 1 in 20 demand scenario, as that is the metric which is used to plan and build the system (to support the 1 in 20 licence obligation).

96 Whilst some of the other approaches may be acceptable, we fundamentally disagree with the Theoretical maximum physical capacity approach being used. For the reasons outlined in the paragraphs below, we do not believe that setting baselines in excess of physical capacity is a sensible way to proceed.

97 Within the document, Ofgem acknowledges that there may be problems with setting baseline levels too high which may not be in the interest of consumers:

- Potential for sterilised capacity which could lead to investments being made which may turn out to be not be the most economic and efficient solution;
- Potential for high buy-back costs where capacity has effectively been 'over-sold' compared with actual capability.

98 However, there is an additional consideration which needs to be taken into account. If baselines are set above the level of network capability, this can remove the incentive for users to signal their true needs in any long-term booking process and hence lead to the situation where the network operator cannot respond in a timely manner to any signals for additional capacity being signalled in the shorter term. This could result in shippers being unable to bring gas to market.

99 In addition, if baseline levels are set above system capability, there is an assumption that a substantial buy-back fund would also be provided to allow the efficient trade off between buying-back that capacity or the provision of extra capacity within the network above the levels funded via the TO control.

100 We therefore continue to believe that the level of baselines should be consistent with the physical capability of the system taking into account the interaction between the various entry points. In addition, the level of the baselines should be set to match the funding provided within the TO price control.

Offtake access arrangements and incentives

(m) ***What threshold should trigger the release of incremental exit capacity e.g. a percentage of the deemed cost of providing the incremental capacity, a fixed number of years of commitment or another approach?***

101 The threshold needs to be set having due regard to the apportionment of risk between key stakeholders. Specifically, the approach might seek to ensure that any investment cost that is specific to a particular user or location is secured by that user, rather than its cost being borne by the wider community who receive no benefit from such specific investment. It might also be considered appropriate to ensure that the regime does not disproportionately recover costs against a user to such an extent that it is inconsistent with their utilisation. Ultimately we believe the level chosen should equate to what would be deemed to be an efficient investment and therefore enter into the NTS asset base.

102 In any model we think it is important that both the network users and National Grid are clear what the trigger level is on an ex-ante basis, as per the current entry regime.

(n) ***How should National Grid NTS be incentivised to release incremental capacity as soon as possible, and should the limit on release be set as a fixed period, for example, three years, or linked to a fixed interval once the relevant planning consents have been obtained?***

103 We are supportive of incentives being placed upon activities which are within National Grid's control. However, given the recent experiences with planning consents, we are firmly of the belief that National Grid has a limited influence over the planning process and hence has little control of the time taken for this activity. As such, National Grid believes that it is appropriate for the release of capacity to be linked to a fixed period once all the relevant planning consents have been granted. However, it may be appropriate to have different time periods to release, depending on the type and complexity of project to be delivered.

104 The incentive structure could then be established to reward the transporter if capacity is delivered ahead of the fixed interval (if that were valued by users) with compensation (based on a liquidated damages approach) being paid if the capacity is delivered outside the fixed interval.

Transitional offtake incentives and revenue drivers

(o) ***To what extent should incentives and revenue drivers for National Grid NTS in relation to capacity for the transitional period represent a continuation of the current "interim" NTS incentives, including the 15 day interruption incentive on the NTS;***

and

(p) ***To what extent should incentives and revenue drivers for National Grid NTS in relation to capacity for the transitional period be consistent with the enduring NTS incentives that will be determined?***

105 At the present time it is difficult to assess whether the incentives and revenue drivers for National Grid NTS in the transitional period should either be a continuation of the current interim arrangements or whether they should be consistent with the enduring incentives. Now that the commercial arrangements for the transitional period are clearer, we would welcome further dialogue with Ofgem on the transitional incentive arrangements. In particular it will be necessary to ensure that the form of the

incentives include a revenue driver to provide additional revenue to fund investment made for providing capacity above an agreed baseline level in the transitional period.

Buy back incentives for entry and offtake

(q) ***Would it be appropriate to treat buy backs from operational constraints differently compared with buy-backs resulting from delayed investment for incremental capacity? If so, should there be two different buy-back mechanisms and what would the advantages and disadvantages be? How could we distinguish between the two types of constraints?***

106 In principle, we would agree with separating operational buy backs from new investments as the risks are both qualitatively and quantitatively different. Such a separation would allow a separate mechanism to be adopted for new investments, as detailed in our response to questions (r) and (u) below. We also believe it would be possible to distinguish between the different types of constraints and would be happy to discuss our views further with Ofgem.

(r) ***Should the existing buy back incentive be refined to ensure an appropriate allocation and management of risk or should a different type of buy back incentive be considered, and if so, what form might this take?***

107 We believe that the current entry regime needs to be changed to more appropriately balance risk and reward. Currently, there is very little upside [there is no explicit buy back allowance for new infrastructure and the theoretical ceiling rate of return of 12.25% (in the first five years of the scheme) is unachievable, given shippers have all the information they need to effectively make their auction bids close to stipulated unit costs]. In addition, we are currently exposed to areas outside our control (e.g. consents).

108 We would therefore support reform of the current gas entry regime to ensure that fixed time periods to provide capacity are accompanied by either more appropriate compensation if the capacity is late (separate buyback pot or compensation rate), or explicit recognition in the timing of capacity provision that this is subject to consenting delays or delays beyond the transmission companies control. The current gas exit and electricity regimes provide some useful features within them which could be used to consider reform of the gas entry regime.

109 In reviewing the current compensation mechanisms within the UNC for shippers it would appear inappropriate for one user in a monopoly position to be able to demand a price for buy back of capacity well in excess of the initial price paid for the primary capacity product and for those costs then to be smeared back across all shippers according to their capacity holdings. It may be more appropriate, in relation to new investment, to have an administered buy back price or liquidated damages for late delivery. If Ofgem is planning to impose significant downside risk on transmission operators for under-performance, then there needs to be a comparable upside and/or a higher base rate of return.

(s) ***Should delay to incremental investment due to connecting pipelines be included in the buy back incentive?***

110 In principle, we would support separating operational buy backs from new investments as the risks are different. Whether we would support the connecting pipeline forming part of the buy-back incentive is dependent upon how the overall compensation arrangements are developed.

(t) ***How should risks be allocated between shippers, National Grid Gas and consumers?***

111 As detailed in our response to question (u) below, we believe the key element is balancing **risk** and **reward** amongst the relevant stakeholders. Although we are willing to consider a range of risk/reward combinations as part of the price control, it should be noted that if Ofgem is planning to impose significant downside risk on transmission operators for under-performance, then there needs to be a comparable upside and/or a higher base rate of return.

(u) ***Would it be desirable for the regulatory regime to enable more flexible contractual arrangements between shippers and National Grid Gas (for example in relation to construction scope)? How might this achieved? What would the advantages and disadvantages be, especially how might this impact on consumers?***

112 We believe that there should be a more appropriate balance of risk (and reward) between shippers and National Grid for the construction of new infrastructure. As mentioned in the answer to questions (n) and (q) above, whilst National Grid has some limited control over the planning consents process, it is largely outside of our control. It therefore feels inappropriate for National Grid to have an obligation to compensate shippers for late delivery driven by events over which we have little control. We also have some reservations about a regime which encourages the setting up of different contracts with different shippers which could be felt to be unduly discriminatory. It may be more appropriate to have an overall cap on our exposure under incentive schemes, rather than a series of liquidated damages contracts which could, when added together, lead to a large exposure (although it may still be possible to cap National Grid's overall exposure in the bilateral liquidated damages contract model). Having said this we are ultimately willing to consider a range of risk/reward combinations as part of the price control.

Interactions between entry and offtake options

(v) ***What are the main interactions between entry and exit, and how this affects the approach to baselines, revenue drivers and buy-back mechanisms?***

113 The main interaction between entry and exit concerns the setting of the levels for the baselines and the amount of remuneration provided by the relevant revenue drivers. National Grid's primary concern is that the baselines and revenue drivers need to be set such that any investment needed to support requirements for extra capacity in the system should be remunerated via either entry alone, exit alone or a combination of both revenue drivers (as appropriate). If the baselines are not set to be aligned, then there is a risk that either too much or not enough remuneration would be received.

(w) ***Should the same approach to baselines and the revenue driver be adopted for entry and exit? What would be the advantages and disadvantages of doing so?***

114 The most important element will be to ensure that the entry and exit revenue drivers are consistent. In this regard a useful test will be to examine whether the additional revenue that may result from credible scenarios relating to incremental entry and/or exit capacity, closely relates to the likely investment costs.

(x) ***Should there be one buy-back incentive covering both entry and exit?***

115 The answer to this question will depend on whether the risks are the same. Further analysis will need to be undertaken once there is more detail as to the baselines for entry and the form of the regime for exit.

Chapter 8 – Incentive Options - Electricity

General Comments

116 We would agree with Ofgem that, given the uncertainties in the external drivers of our costs, it would be useful to incorporate revenue drives in our price control. Such drivers would reduce (but would be extremely unlikely to eliminate) the risk of investment costs exceeding those funded in the price control.

117 Experience in the last control suggests that there is scope to improve on the non-locational generation volume driver in electricity transmission control (Gt), for example, to provide additional revenues to cover costs associated with higher than planned demand and also generation developments in areas with higher costs than the forecast average.

118 We are keen to work with Ofgem over the coming months to develop cost reflective revenue drivers. We are currently doing work to determine whether it will be possible to develop revenue drivers to meet the high level objective of adjusting revenue within a price control for investments which were not provided for in the main price control. However our work to date would suggest that it will be difficult to design very accurate revenue drivers and therefore we would currently see the revenue drivers as effectively being a "down payment" for necessary investments during the price control period. In the event that the revenue drivers had provided insufficient remuneration (or too much) we believe this should be adjusted as part of the next price control such that the transmission company was left whole.

119 In relation to the commercial regime, as noted in Chapter 6, we believe there is merit in developing "user commitment" models however we do not believe detailed models can be developed without having a clear understanding of how the new regime would interact with our wider obligations, incentives and revenue drivers. We believe a user commitment model would work in the context of an Option 2 type approach as outlined in our comments relating to Chapter 6 (ie the user commitment is **not** the sole mechanism for adjusting revenues).

120 In any case developing revenue drivers which are not dependant upon the introduction of a new user commitment model would appear to be the only sensible option given a user commitment model in electricity would require implementing through changes to the commercial framework. It would therefore seem that decoupling regulatory revenue drivers from the commercial framework is necessary to allow the flexibility to ensure a price control settlement could be agreed, by the end of 2006, whist allowing the optimum time to consider and introduce changes to the commercial framework.

121 Having gained clarity on the link between user commitments and revenue it would seem that the questions raised in Chapter 6 namely; '*What should the user commitment apply to (all capacity or incremental capacity)?' and 'Whether the commitment is provided for both entry and exit or just entry?'* are particularly pertinent in electricity given the current commercial framework. In assessing these questions a clear assessment should be undertaken to understand the costs and benefits of moving from the status quo position. Our initial view would be the costs and benefits associated with obtaining user commitment for **all** capacity, in the context of electricity entry, appears to have merit given the current issues associated with the GB queue, whilst the **current** case for such a regime in electricity exit appears less clear.

122 We would endeavour to bring forward some Strawman proposals to illustrate the differences between a full user commitment model against an incremental only

approach to Ofgem's February workshop which would aid the industry in progressing such a cost benefit assessment.

123 In relation to the other main elements consulted upon within this chapter, we would **not** support a proposal to replicate the current gas entry buy-back regime in electricity. The problems with the current buy-back entry regime are covered in more detail in our response to chapter 7. In terms of system performance and reliability we currently believe that adapting the current Transmission Network Reliability Incentive scheme (TNRI) most closely aligns National Grid's incentives with the interests of consumers.

Comments on the questions where views were invited

Has Ofgem focused on the appropriate issues to be addressed in the light of operation of the current price controls?

124 We welcome the discussion that has been initiated in this consultation regarding user commitment and revenue drivers and we are supportive of any mechanism which can result in more efficient and timely investment and which maintains the right balance of incentives on the transmission licensees.

125 One very significant area that we believe has not been considered in this document, and which we have addressed elsewhere in our response, is the interaction between user commitment and incentives and our wider obligations. It is very difficult for National Grid to reach any firm or detailed proposals on user commitment models or any associated revenue drivers unless there is consistency with and clarity of both our obligations and those of the other transmission licensees.

126 We fully support the development of incentives which enable revenues to be adjusted to cater for new investments which are required but which were not foreseen at the time of the last price review. However, in the case of user commitment, we are concerned that there is scope for uncertainty regarding our obligations to invest when user commitment is **not** forthcoming or fully aligned. There are many reasons why a suitable user commitment signal may not be available at the appropriate time including:

- the perceived or real incentives to purchase capacity in the short term;
- a user's inability to make a long term financial commitment e.g. due to uncertainty and risk or the financial status of their project;
- lumpy investment being triggered by a relatively small user commitment signal;
- lumpy investment required at an early stage to manage a user signal that is ramping up gradually over a number of years e.g. natural demand growth; and
- a user's lack of understanding or misinterpretation of the requirements/obligations.

127 Therefore, as part of the discussions regarding user commitment mechanisms, it will be important to also have clarity as to how these will operate in tandem with National Grid's wider obligations to build, operate and maintain the network.

128 In addition to the above, consideration also needs to be given as to the working of the revenue interaction between National Grid as GBSO and the other transmission licensees. The interaction of any new regime with the other Transmission licensees

must be given careful consideration, with appropriate changes made to licences, codes and methodologies. In particular, we would expect the revenue recovered through transmission charges by the GBSO to reflect the revenues to be paid to the Scottish TOs. For example, if the revenue paid to a Scottish TO in a given year increases then we would expect the revenue recovered by the GBSO to increase at the same time, otherwise National Grid may end up financing the difference between GBSO transmission charges and Scottish TO's incentive payments. Furthermore, the incentives and obligations on all licensees will need to be consistent. Two licensees interpreting their obligations and incentive schemes differently could result in inefficient investment decisions.

129 We believe there are two other key areas worthy of consideration: the process for implementation and the links to embedded benefits. These areas are covered in the two paragraphs below.

130 The existing amendment process may not enable the efficient consultation and implementation of major changes such as the introduction of a user commitment regime. Consideration should be given to an alternative process that could be more efficient and facilitate discussion.

131 Ofgem are currently consulting on embedded benefits within the transmission charging methodology. Unless a user commitment model effectively includes embedded generation, then a new embedded benefit could be established which would drive generation to connect uneconomically at distribution voltages.

Is it appropriate to develop more sophisticated revenue drivers under a 'status quo' option – and if so, what designs of revenue driver might be considered to be most appropriate and worthy of further detailed analysis and quantification?

132 In weighing up the options of developing more sophisticated revenue drivers along the lines highlighted in Ofgem's 'status quo' option against the alternative of moving to a full user commitment model, a clear assessment should be undertaken to understand the costs and benefits of moving from the status quo position. Our initial view would be the costs and benefits associated with obtaining user commitment for **all** capacity, in the context of electricity entry, appears to have merit given the current issues associated with the GB queue, whilst the **current** case for such a regime in electricity exit appears less clear.

133 In any case developing revenue drivers which are not dependant upon the introduction of a new user commitment model would appear to be the only sensible option given a user commitment model in electricity would require implementing through changes to the commercial framework. It would therefore seem that decoupling regulatory revenue drivers from the commercial framework is necessary to allow the flexibility to ensure a price control settlement could be agreed, by the end of 2006, whilst allowing the optimum time to consider and introduce changes to the commercial framework.

134 Given that it would appear necessary, at least in the interim, to develop more sophisticated revenue drivers for 1 April 2007. We are keen to work with Ofgem over the coming months to develop cost reflective revenue drivers. We are currently doing work to determine whether it will be possible to develop revenue drivers to meet the high level objective of adjusting revenue within a price control for investments which were not provided for in the main price control. However our work to date would suggest that it will be difficult to design very accurate revenue drivers and therefore we would currently see the revenue drivers as effectively being a "down payment" for necessary investments during the price control period. In the event that the revenue drivers had provided insufficient remuneration (or too much) we believe this should be adjusted as part of the next price control such that the transmission company was left whole.

135 Given the above, and our recent work to date on driver design, we would make the following comments as to the most appropriate forms of revenue driver design:

- In so far as the existing network has sunk investments, we believe it is important to establish baselines such that movements in revenue drivers do not reduce revenues required to finance such existing investments.

- Given the complex meshed, multi-nodal, nature of our networks we believe that revenue drivers will give at best only an approximation of the need for network investment. In particular:

    - While detailed nodal revenue drivers may, in theory, give greater scope to address a wider range of uncertainties, there are significant challenges associated with identifying stable unit costs for such drivers due to limited data and investment case studies.

    - There are also challenges in terms of operating complex and detailed nodal revenue drivers in practice. This complexity is reduced to a manageable level only if certain zonal/regional drivers are used.

- The interactions between entry and exit mean that in some areas of the network entry reductions (e.g. generation closure) or reductions in network exit levels (e.g. through embedded generation entry) can have the same affects on wider requirements for network capacity. It will be necessary to address the impact of generation closure as part of the TO price control or as part of the development of revenue drivers.

What are the advantages and disadvantages of user commitment models, as characterised above, in the context of electricity transmission?

136 We believe there are potential advantages to be realised by developing a stronger user commitment regime. In particular the information should provide greater certainty of the generation and demand background which is used by National Grid to make investment decisions, and for Ofgem when undertaking a price control review. As mentioned in our response to Chapter 6 we would see the greatest benefits arising in relation to electricity entry. By requiring all entry users both existing and new to make a commitment then not only will uncertainty be reduced in terms of new generation, but better information will exist regarding future plant closures. This has the potential to free up existing capacity for new users.

137 A stronger user commitment may also help with the large number of applications for system access that are currently being progressed. The requirement to make a larger commitment may force some projects to withdraw their applications, enabling more viable projects to proceed more quickly. This may also be seen as a disadvantage by many if too many projects are forced to withdraw.

138 Greater certainty would be delivered if the capital expenditure is automatically included in the Regulatory Asset Base once the agreed user commitment has been made. This will also ensure future price control reviews can focus on other areas of capital and operational expenditure.

139 It should be noted however that there may certain disadvantages associated with such a regime. Other stakeholders may want to comment on at what levels financial commitment may act as a barrier to entry, reduce competition and may have an impact on meeting the renewable targets.

140 On balance we believe that a careful cost-benefit assessment is required to assess whether the advantages in increased commitment delivered by such a user

commitment model outweigh the increased cost burden that the mechanism might place on the industry in terms of increased financial commitment – with our initial view being that the case for more reliance on user commitment is more clear-cut for electricity entry than for either electricity or gas exit.

What do respondents consider to be the most appropriate answers to the detailed design questions highlighted above for user commitment models? Are there any further questions that should be added to the list?

141 The detailed design questions have been addressed below. We have not considered any additional questions at this time.

How should the baseline capacities be set?

142 If the release of new capacity is undertaken using an 'unconstrained' approach then the requirement for a baseline within the capacity release mechanism is removed. Any user requesting an increase would get the capacity at a certain point in the future, identified as part of the connection.

143 Any agreement for the release of additional capacity could, as a result, trigger a revenue driver. The use of TEC may be an appropriate driver, however, this would depend on the overall revenue driver framework, as TEC would ignore the affects of changes in embedded generation and demand, which may also drive investment.

What is the mechanism whereby users (current and prospective) commit their profile of demand for network capacity – and are there any alternative mechanisms which deliver similar effects?

144 A booking window approach would seem the most appropriate mechanism to allow users to commit to their requirements for network capacity, however the interaction with the requirement for new users to establish a firm connection date must be considered. Moreover, a user commitment must take account of the requirement to obtain a physical connection to the network before, or as well as, to making any firm long term financial commitment for a given period.

145 In any case we believe that user commitment and capacity release methodologies must be nodal as it is this level of information that is required to plan and operate the system.

What should the network user be committing to?

146 For electricity entry commitments, we support the concept of both new and existing users committing to paying the prevailing transmission tariff for a minimum number of years. We believe that a model should treat both new and existing users consistently and we would therefore support an approach whereby the minimum number of years was a generic number for all users. This would need to be set at a level which is sufficient to support any associated investment decisions as well as recognising that if applied to existing users, that there could be a significant change from the status quo.

147 Any user commitment required from the user should be consistent not only across both new and existing users, but also across both gas and electricity. It would not seem equitable that a new gas fired power station would require one level of user commitment for their gas NTS connection and a completely different level for their electricity transmission access.

What would trigger the release of incremental capacity?

148 As mentioned above, we see the merit in a simple approach to entry user commitment whereby both new and existing players are required to give the same signals. If this is achieved by a generic X years of tariffs, then this could be the minimum requirement to trigger the release of incremental capacity. We would welcome a direction from Ofgem on the appropriate level for this commitment as ultimately the level chosen should equate to what would be deemed to be an efficient investment and therefore enter into the Regulatory Asset Base.

When would incremental capacity be released?

149 As mentioned elsewhere, we would support an approach that recognised the consent risk and other major construction issues. There is also the desire not to jeopardise any applications for planning consent which could occur if system access is granted prior to the construction of new transmission lines which are justified on the basis of the requests for new capacity. On the basis that incremental capacity release is linked to the time taken **following** successful planning consent, there would appear to a choice as to whether capacity should be released in a fixed time period or a variable time period, which may take into account project specific issues. We would be happy to discuss the relative merits of these two options further with Ofgem.

How would scarce capacity be allocated in the short term?

150 A short term capacity release methodology can be developed however a model utilising detailed nodal or zonal baselines would be complex to develop and operate, and would require significant regulatory intervention. A simplified approach based on non-obligated short term capacity release may give many of the benefits whilst being easier to implement. It may be that an appropriate model to manage the release of short-term capacity would be to incentivise the System Operator to release additional capacity to encourage the maximum use of short-term available capacity. This would allow the balance to be achieved between releasing additional capacity and the resultant increased risk of constraint costs.

151 However, any mechanism would need to be address the requirement for any short term release not to create undesirable consequences with users looking to book capacity in the shorter term rather than via user commitment in the longer term.

152 A further consideration with a short term capacity release regime is whether it would also allow the early connection of new plant prior to completion of associated connection works. Whilst this may provide some temporary remediation, it would seem unlikely that a new generation project would commit to early construction unless there is a firm commitment at an early stage regarding the level of capacity or volume that will be available at the time of connection.

What would happen if allocated capacity (either under the baseline, or as a consequence of incremental capacity being released) could not be delivered physically at any point?

153 We would **not** support a proposal to replicate the current gas entry buy-back regime in electricity. The problems with the current buy-back entry regime are covered in more detail in our response to chapter 7. We would also highlight that the concerns associated with who bears the risk associated with consents are even more pronounced in electricity. Consent issues can lead to significant lead times to deliver new infrastructure, which in relation to the Second Yorkshire line took over 10 years.

154 The concept of the GBSO buying back capacity if new investment was not delivered on time would seem inappropriate in electricity, where the TO's are effectively

responsible for delivering the new investments and not the GBSO. If any model were introduced obliging the GBSO to buy-back capacity when incremental investments have not been delivered, there would need to be an explicit back to back arrangement with the TOs.

What would happen if a user did not book rights?

155 Once a user commitment regime is in place, then it would need to be protected and reasonably strong incentives need to be in place to encourage users to make the necessary commitments. A balance needs to be struck between facilitating access through any short term product and the need to signal network capacity requirements through longer term commitments.

156 It should be acknowledged however that whilst users may have a good idea of their capacity requirements over a given time frame, it is likely that there will be greater uncertainty in the longer term. A regime which effectively removed all access rights at the end of a longer term booking may inevitably result in access being denied to plant that is perfectly viable –although this would presumably be on the basis that the capacity has been purchased by an alternative customer. Beyond the possible availability of short-term access products, a possible solution to these issues may be within a non-obligated release regime, in which a generator would have access for a fixed period after longer term rights have expired.

What is the appropriate means of managing the process to develop user commitment model options given the interactions with the revenue restriction, Connection and Use of System Code (CUSC), charging methodologies and other codes and documents? What role should Ofgem adopt in this process? What role should NGET take, given its role of GB System Operator and its obligations in respect of charging methodologies?

157 A large part of the changes to the access regime that would be required to introduce a new user commitment model would be within the Connection and Use of System Code. The existing amendment process works well for incremental change to the framework – however, we are not confident that it would enable the efficient introduction of more fundamental changes to the commercial arrangements such as the user commitment models being considered. The last significant industry changes, those for BETTA, were achieved using powers established in the Energy Act and did not utilise the existing amendment process.

158 We would support the development of a revised amendment process which would enable the efficient assessment, consultation and implementation of a new user commitment model, and which facilitated sensible cross code discussion. A refinement of the process to that seen for BETTA, involving industry-wide consultation may be workable, with Ofgem taking the overall lead.

What are the advantages and disadvantages of more extensive system reliability and performance reporting – and how might such metrics be linked to financial incentives?

159 From the options contained in the consultation document, the current Transmission Network Reliability Incentive scheme (TNRI) in England and Wales seems to most closely align National Grid's incentives with the interests of consumers. The output most valued by consumers is the maintenance of supplies (i.e. low losses of supply) or the rapid restoration of supplies if losses do occur. In relation to the alternative approaches contained in paragraph 8.48, it is currently not clear that any of the approaches would better meet the interests of consumers. In particular we cannot see any logic for a 'penalties only' scheme.

160 We would acknowledge that, in addition to loss of supply, transmission customers value network availability and therefore consideration could be given to a wider basket of output measures. However, it should be noted that the existence of the SO

incentive scheme (BSIS) to effectively manage balancing costs already includes transmission system constraint costs and, as such, already provides an incentive which encourages optimisation of network availability.

161 In the event that more explicit incentives are created in relation to network availability it would be necessary to take care how system availability measures are interpreted. For example, increased asset replacement will in the short-term reduce system availability. It is important to recognise that the purpose of asset replacement investment is to maintain the performance and reliability of the prevailing transmission network in England and Wales in the **long-term**. Moreover, a short-term decrease in system availability as a result of increasing capital expenditure will increase the short-term risk of loss of supply, given that more of the network will be exposed to single event risks. This effect would need to be taken into account in the setting of any revised targets if the current form and scope of the England and Wales TNRI was to continue into the next price control.

162 It would seem appropriate that as a matter of principle National Grid should be incentivised on areas within its control. As such we are also keen to review the current exceptions and exclusions within the TNRI scheme particularly in light of experience to date and the slightly different approach contained within the recent Scottish proposals on network reliability

Chapter 9 – Financial Issues

General Comments

163 We note Ofgem's invitation to provide views on the analysis required to determine an appropriate cost of capital over the next few months. We look forward to taking a full and constructive part in the debate on this key topic areas in due course. In the meantime we have restricted our response to this consultation to the specific views invited.

Comments on the questions where views were invited

Whether the level and trend of key financial indicators consistent with a credit rating that is comfortably within investment grade remains the most appropriate approach to assessing the ability of the licensee to finance its regulated business

164 We believe that continuing to target financial ratios which are consistent with an A grade credit rating, as with DPCR4, remains the most appropriate way of ensuring that licencees can continue to finance their functions. We also believe that for NGET and National Grid Gas Transmission it will be appropriate to assess the financeability of the licensed entity on a stand alone basis, even if they are part of bigger entities.

The financing of the asset replacement cycle

165 There are two main potential approaches to financing the asset replacement cycle:

(a) Allow gearing to fluctuate in line with asset replacement requirements and adjust the allowed return to reflect higher levels of equity when asset replacement cycles are low. This option leaves shareholders responsible for providing the balance sheet flexibility when high levels of asset replacement are required.

(b) Maintain gearing levels at theoretical maximum levels throughout the asset life cycle, minimising allowed returns, but requiring customers to provide additional financial flexibility to manage periods of high asset replacement.

166 Historically, Ofgem have followed the second approach, and we think that it would be inappropriate to change the regulatory treatment at this point of the asset replacement cycle.

Whether an ex ante approach to setting tax allowances (with an ex post adjustment for gearing and interest expense where relevant) is still appropriate

167 We support Ofgem's move to post tax regulation. We believe that in general ex post adjustments should only occur where gearing is significantly above regulatory assumptions, however the mini review year a full ex post adjustment should take place irrespective of the gearing level, as this formed a part of the final proposals package.

Gearing issues, including:

- ***Whether a common assumed level of gearing should be adopted for all transmission companies, or***
- ***Whether company specific gearing assumptions should be adopted, and***
- ***What level of gearing may be appropriate***

168 We believe that UK Transmission businesses face broadly similar business risks. Nevertheless, there are specific factors relating to some of the individual businesses being assessed. These include the following:

(a) Significant pension deficits are likely to reduce the level of gearing that can be sustained.

(b) Large capex programmes are also likely to have a negative impact on credit profiles.

(c) The existing, and likely future, gas Deep SO incentives, even in the unlikely event that they produced exactly the correct revenue outcome, would not fully mitigate the adverse credit rating effects of large capital expenditure programmes. Consequently, financeability assessments will need to bear in mind the possibility of substantial additional capex obligations, and provide headroom for these to be financed.

(d) The last Transco price control was set assuming a BBB credit rating. A single A rating for Transco would be at gearing levels significantly below 60%.

(e) A reduction in depreciation as a result of the cessation of pre vesting depreciation reduces key cash flow measures as a proportion of RV, for example Funds from Operations and retained Cash Flow. Other things being equal, this will reduce the level of gearing that can be sustained.

The principles that should apply for assessing past capital expenditure in excess of allowances

169 We believe that the categories outlined in the open letter issued as part of the Gas Distribution Network sales process represent an appropriate framework for assessing the efficiency of past capital expenditure. However, we believe that, for Electricity Transmission in **2006/7,** a different framework should apply, where capital expenditure in excess of allowances should be either deemed inefficient, or included in the RV with an allowance for lost depreciation and return in 2006/7. This is due to the interim nature of the capex allowance in the mini review.

The cessation of pre vesting regulatory depreciation for electricity transmission companies

170 We believe that the cessation of pre vesting depreciation should be treated in a manner broadly equivalent with that of the DNOs, but that a full assessment should depend on the overall financial position of the business concerned.