

Transmission Price Control Review – SSE response to 3rd Consultation

1. Form and structure of the price control

Shorter or longer price control periods

- 1.1. We do not believe that Ofgem should alter the existing five year period of all or some components of the price control. In our view, the five year control strikes an appropriate balance between incentives to operate efficiently and uncertainty for customers and licensees of costs/demands over the price control period.

Differential rates of return

- 1.2. We will be commenting in more detail on the split cost of capital proposal in our response to the joint Ofwat/Ofgem consultation on the subject. We are generally concerned that the proposal for a split cost of capital could actually increase perceptions of regulatory risk, rather than, as intended, reduce it. We also believe that, provided the cost of capital is set at a level sufficient to encourage equity investment in utilities, in most cases any residual financeability concerns should be capable of being addressed through tilting depreciation. That said, the profile of SHETL's investment is markedly different from other utilities. In the scenario one forecasts submitted with our BPQ, for example, we illustrated that potential investment could be over £1bn in the next price control period. When put in the context of a current RAV of £300m, this raises obvious financeability issues. In the first instance, this underlines the need for an appropriate cost of capital, but it may, unlike for the sector generally, also point to a need for different regulatory solutions.

Question 2.1: Do you think the standard RPI-X framework needs to be refined or augmented in its application to the transmission licensees?

- 1.3. We agree with the conclusions from Ofgem's earlier consultation that the broad RPI-X framework remains appropriate. This maintains the well-established incentive framework for the licensees on their controllable costs.
- 1.4. In this context it is clear that there are some costs for all licensees which are subject to greater uncertainty and therefore less controllable. These costs relate to the major infrastructure requirements for renewable generation. The potential major investments for major new LNG terminals might also fall into this category.
- 1.5. In general, the level of operating costs and the volume of non load-related expenditure should be capable of reasonably accurate forecasting based on historic trends together with a robust assessment of business plans and asset replacement strategies. In converting the volume of non load-related capital expenditure into a capex forecast, unit costs of the various plant items need to be developed. In this context, we have recently experienced some unexpected cost variations due to variations in commodity prices and potential under capacity in the supply chain. The underlying causes of these price increases,

the likely longer term trend and the effect on unit prices will need to be addressed in formulating price controls.

- 1.6. With this caveat, we believe that operating expenditure and non load-related capex should be funded through an ex-ante allowance in the normal RPI-X methodology. This should be augmented through rolling incentives and information quality incentives as discussed in response to question 2.2.

Categorisation of load-related capital expenditure

- 1.7. The volume of a number of elements of the load-related capital expenditure forecasts can also be reasonably well estimated but are also subject to our concerns on unit costs noted above. There are five main categories of load related capital expenditure: Connection; entry triggered infrastructure; general infrastructure; exit triggered infrastructure and; Transmission Investment for Renewable Generation (TIRG) capex. Our approach to the funding arrangements for these elements of load related capex in the RPI-X framework are further discussed below.

Connection

- 1.8. The "shallow" connection works are separately identified and directly chargeable either as a full capital contribution or as annualised payments. No revenue allowance need to be explicitly set for this type of investment since the costs are recovered directly from customers through connection charges.

Infrastructure Entry Triggered.

- 1.9. The entry-triggered infrastructure consists of both preconstruction and local infrastructure works. Pre-construction expenditure relates to the necessary detailed design, route finding, environmental assessment and consenting procedures required before construction work starts on any project, including TIRG projects. As offers are made and accepted, this work becomes a contractual obligation on SHETL to progress.
- 1.10. Each connection will also require a degree of local infrastructure work to connect them. This would have been charged as connection under earlier methodologies, but under NGET's "shallow" charging methodology is funded as infrastructure. Our submission includes for 3GW of new renewable generation in this category. While it is not possible to be precise about which specific generators will be successful in obtaining consent, it is likely that we will need to cater for 3GW of generation, since this reflects the contractual position with renewable generators and the consensus view of various stakeholders of the most likely level of generation.
- 1.11. Since the level of expenditure is subject, in aggregate, to limited uncertainty, we believe that entry-triggered infrastructure capex should therefore be covered through an ex-ante allowance in the normal RPI-X methodology.

General Infrastructure

- 1.12. General infrastructure refers to other infrastructure works not directly attributable to generation or demand and covers such works as may be

required to improve operation flexibility, to deal with fault level problems, or for protection enhancements.

- 1.13. Since the volume of this work can be reasonably forecast, we believe that general infrastructure capex should be covered through an ex-ante allowance in the normal RPI-X methodology

Infrastructure Exit Triggered

- 1.14. The exit triggered infrastructure works are a lower order of magnitude and consist of work required to cater for growth in demand on the transmission network.
- 1.15. The forecast is based on likely requirements which are subject to a limited degree of uncertainty. In common with the approach in previous price controls, we believe that exit-triggered infrastructure capex should be covered through an ex-ante allowance in the normal RPI-X methodology

TIRG Infrastructure

- 1.16. Finally, the aggregation of new generation connections drives deeper reinforcements to the transmission network. It is this type of expenditure which was detailed in the studies by the three licensees in the "RETS" report and studied by Ofgem's consultants SKM in finalising Ofgem's proposal for funding of Transmission Investment for Renewable Generation (TIRG). This TIRG investment on a small number of major projects is driven by the aggregation of generation projects gaining consent, and their location. As the particular possible projects have already been identified, we continue to believe that a version of the TIRG mechanism would be the most appropriate way to fund the small number of major projects that would be required during the price control period.

Question 2.2: Do you think that rolling incentive mechanisms are the most appropriate way to deliver a consistent strength of incentives over time, and do you think they are applicable to transmission licensees?

- 1.17. We believe that rolling incentive mechanisms should be applied to any costs for which an ex-ante revenue allowance is determined. In addition, in setting the two-year extension for the Scottish companies, a rolling incentive was applied to the capital expenditure from 2003 onwards. We believe this mechanism is an important part of the price control package as it removes perverse incentives regarding the timing of efficiency improvements.
- 1.18. We therefore believe that Ofgem should make clear that the "capex roller" incentive will be applied to capex for the next price control period. This would solve the periodicity problem of efficiency savings and would complement the information quality incentive proposed by Ofgem.
- 1.19. In applying the capex roller, Ofgem will need to take into account two aspects of the incentive. First, it will need to make it clear that capex savings during the 2007-2012 period will be kept by the company for a minimum of five years and the 2012 price control will provide for recovery of those benefits. Second, in relation to efficiencies made between 2003 and 2007, an

adjustment should be made to allowed revenue to recover those savings in the 2007-2012 period. In the case of SHETL some of this revenue was allowed in regard of efficiency savings prior to the two-year extension to 2007. However, the capex roller incentive revenue in that period did not remunerate all of the five-year retention of savings made before 2005 and this will also need to be addressed in calculating allowed revenue from 2007. It will also need to reflect five-year retention of any savings in 2005/06.

- 1.20. We would be firmly opposed to the suggestion that efficiency savings would only be retained for three years, rather than the traditional five year period that has applied to every price control in the sector hitherto. As Ofgem have rightly identified, the transmission licensees are entering a phase of higher investment than in recent years (albeit to different degrees). It is therefore particularly vital that incentives to operate efficiently are not weakened at this point in the investment cycle.

Question 2.3: Given the large bids made by some licensees for asset replacement expenditure, how do you think the regulatory regime should look? Do you think that a "information quality incentive mechanism" is the best way to improve our information on efficient costs, by rewarding licensees more if they accept more challenging cost targets?

- 1.21. The information quality incentive mechanism described in the paper is similar to the "sliding scale" mechanism introduced in electricity distribution. This mechanism provides for different returns for companies depending on the results of the review of capex forecasts by Ofgem's consultants and the difference between outturn and forecast plans. We therefore believe that a similar mechanism for transmission investment could improve Ofgem's information on efficient costs and provide improved incentives in relation to capex forecasts.

Question 2.4: Are additional measures needed to promote innovation? What is the scope for innovation by transmission licensees to benefit consumers?

- 1.22. We believe that there is scope for innovation in transmission to benefit consumers. The recent approval of the registered power zone for Orkney is a good example of how the innovation incentive in distribution has brought a tangible benefit for renewable generators in the islands. We believe that similar arrangements in transmission could also provide benefits through, for example, investigating further options to maximise usage of existing transmission networks.
- 1.23. We therefore believe that Ofgem should introduce IFI and RPZ incentive arrangements in transmission, along similar lines as in the distribution price review. In particular, the IFI scheme has the potential to deliver significant innovation in transmission and we would see no logic in a separate treatment of distribution and transmission in this regard.

Question 2.5: Should the current form and scope of System Operator (SO) incentive schemes be adopted in the next price control period?

- 1.24. Under BETTA, new systems are in place to ensure efficient investment in transmission systems where this could reduce balancing costs and these

appear to be working well. It would not therefore appear appropriate to consider changing the form and scope of the SO incentive schemes at present, particularly given the proposals for 2006/7 have not yet been agreed and may be subject to a Competition Commission reference.

Question 2.6: To what extent should incentives applying to Transmission Owner (TO) costs and SO internal costs be equalised? Should these costs (e.g. staff costs and IT spend) form part of the TO price control?

- 1.25. Under BETTA, there are new interactions between NG as system operator and the Scottish transmission licensees. It will be important to ensure that any revised incentives on NG's SO and TO costs do not undermine incentives for the Scottish TOs. We are therefore not opposed to equalising NG's internal cost incentives, provided that the Scottish TOs continue to be treated equitably compared to NG's TO operation.

Other Issues – Starting RAV

- 1.26. In respect of the opening RAVs for the Gas Distribution Networks (GDNs), we do not believe there is value in re-visiting the RAVs for the period January 2001 to March 2002. National Grid would have to provide the information, and in any case this will be confused by the issues involved in separating the price controls and “sculpting” RAVs. To the extent that there is a material difference between the forecast closing RAV at the end of the last price control period and the outturn position, this should be a matter of bilateral discussion between NGG and Ofgem. In the interests of regulatory certainty there should be no adjustment to the GDN RAVs.

2. Electricity incentives

Question 3.1: Do you agree with our conclusion that the use of locational revenue drivers is the most appropriate way to set allowances for the electricity transmission licensees in the context of significant uncertainty over the future demand (and location of that demand) for network capacity?

2.1. We are firmly opposed to the use of locational revenue drivers to set allowances for transmission licensees. In our response to the December TPCR consultation, we set out the key problems with revenue drivers and our proposed solution (an enhanced version of the "TIRG" mechanism already in the licenses). We are therefore very disappointed that this consultation has not addressed the issues we raised at that time and that there has been no further discussion on the problems and possible solutions. The key problems are:

- Accuracy of the revenue driver;
- Timing of revenue streams;
- Lumpiness of investment – potential for unrecovered income for spare capacity; and
- Increased risk.

Accuracy of Revenue Driver

2.2. In setting a locational or nodal revenue driver it would be necessary to identify the cost of the project and the MW capacity released. In its simplest form, this would produce a £/MW revenue driver for the particular project. This would clearly be onerous and would require frequent intervention from Ofgem. A more generic revenue driver for large parts of the transmission system would raise separate issues. In particular, it would not be sufficiently accurate and could lead to perverse incentives to only construct projects in areas where the revenue driver was adequate to cover costs, and to delay otherwise efficient investment in transmission infrastructure.

2.3. We agree with Ofgem that, if revenue drivers were set, they should as far as possible be fixed for the duration of the price control. Otherwise this defeats the objective of revenue drivers which are intended to avoid the need for repeated regulatory intervention mid price control.

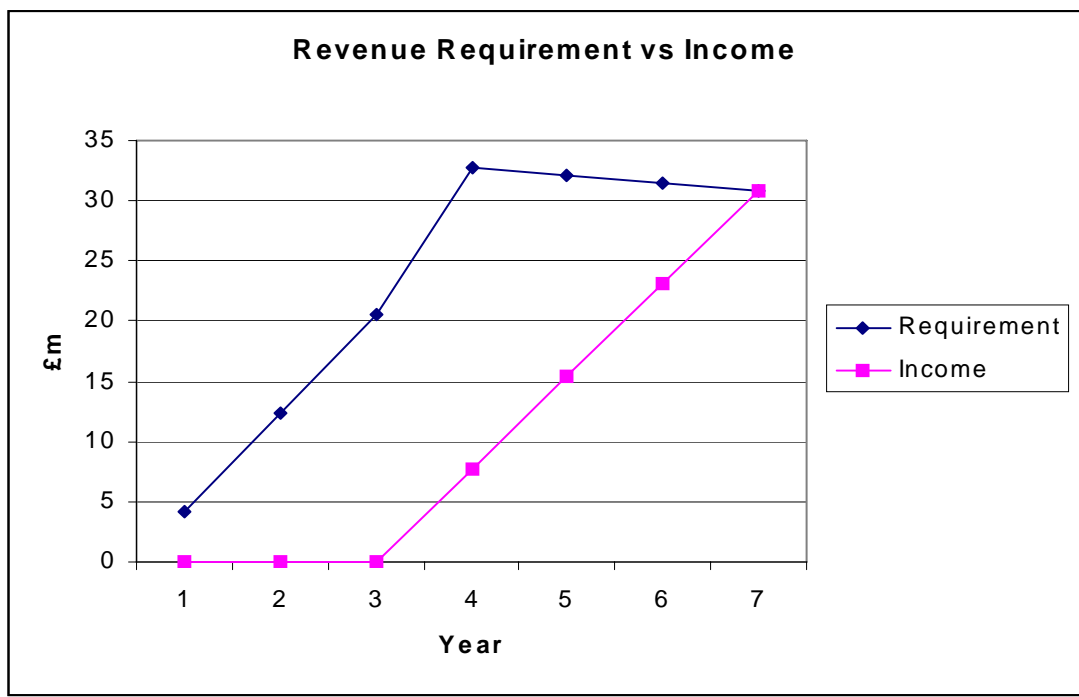
2.4. However, this also illustrates another fundamental failure in the revenue driver concept. To the extent that revenue drivers are not cost-reflective for the duration of the price control, then investment decisions will be distorted. Costs and patterns of demand will change over time, particularly at a regional level, and hence setting regional revenue drivers that are at all times cost reflective will, in our view, prove to be impractical. In this context, and as evidenced by recent Ofgem consultations, we note that NGG failed to set cost-reflective revenue drivers in the gas entry revenue driver regime, which is based on similar principles.

2.5. In addition, the economy is currently experiencing unprecedented volatility in commodity prices and contractor rates, reflecting UK and global economic conditions, as explained in part 5 relating to the forecast capital expenditure. This will also affect the accuracy of a revenue driver over the course of the price control period and makes it difficult to set the revenue driver parameters in advance.

- 2.6. In any event, "truing up" would be required at the next price control to ensure that transmission licensees were adequately rewarded for the investment. This would introduce an additional risk for licensees.

Timing of income

- 2.7. The revenue driver, even if perfectly matched between the capital cost of the project and the MW capacity released, results in a significant mismatch between the revenue requirements of the TO and the revenue obtained through the revenue driver. This is illustrated in the graph below, which shows a three-year construction programme for a major project, followed by a four year period in which the capacity is taken up.



- 2.8. This illustrates the major problem that the timing of the revenue stream is mismatched to the revenue requirements necessary to fund the investment. In many cases this would result in funding for the project not being received until the next price control period, which would be unacceptable. Alternatively, licensees could be incentivised to inappropriately delay investment until generators had connected, which would be inconsistent with current UK energy policy.

Lumpy investment

- 2.9. The chart above also illustrates the problem of lumpy investment and the potential risk of unfunded spare capacity. If only sufficient capacity to fill 75% of the investment were sold (for example the year 6 position) then only 75% of the long term funding would be secured, even though the minimum increment of capacity had been constructed.
- 2.10. For these reasons, revenue drivers also encourage the absolute minimum investment to meet today's capacity commitments with no scope for "future proofing" even when this can be shown to be more efficient.

Increased risk

- 2.11. The types of revenue driver discussed so far by Ofgem would significantly increase risk on transmission licensees. The accuracy of the revenue driver, the mismatch between investment and revenue and the lumpy investment would require truing up at the next price control, increasing the regulatory risk that some investment might be "disallowed".
- 2.12. To put this into context for SHETL, the major projects listed as potential projects for a TIRG type of funding mechanism range from £50m to several hundred million pounds. We welcome Ofgem's conclusion in paragraph 3.14 that "exceptionally large investment needs" could not be funded through a revenue driver. However even the smaller scale £50m project represents about **20%** of the SHETL RAV. A project of a similar proportion in National Grid's system would be over **£1bn**. In our view, it is inconceivable that National Grid would undertake a billion pound project on the basis of a £/MW revenue driver. It is therefore unreasonable to expect SHETL to do the same. In our view, even £50m projects for SHETL should be funded through a TIRG type mechanism.
- 2.13. For SHETL in particular the potential investments are such that there are considerably increased risks in financing the investments and this needs to be reflected in the cost of capital.

Consistency of approach

- 2.14. We note in paragraph 4.15 of the consultation that Ofgem propose to calculate a unique revenue allowance for new gas entry points. This appears to be very similar to what we have proposed for the major infrastructure investments in electricity transmission. A trigger level is identified and a revenue allowance is set based on the efficient level of investment to reinforce the network to the required standard. If this mechanism is being proposed in gas, we see no reason why it should not be applied in electricity.

Local connection and infrastructure

- 2.15. Setting aside the major infrastructure works, there is a subset of expenditure required to connect generators to the existing infrastructure. Previously, this would have been classified as connection work and charged directly to the generator. However, this is now classed as infrastructure and a revenue allowance needs to be set for this work. We have been studying this type of expenditure in detail to determine an appropriate mechanism to deal with the funding of this work.
- 2.16. On the basis of Ofgem's initial views, we have studied the possibility of using revenue drivers for this subset of work. This indicates that there are considerable problems with revenue drivers even for this work, and we have set out in appendix 1 a number of worked examples to illustrate these problems. These are based on actual projects that have been provided to NG for the purposes of providing a connection offer to new generators.

- 2.17. The worked examples demonstrate a number of conclusions:
- (a) For projects that are located close to existing infrastructure (no new circuits involved) the £/MW or £/site charge to connect is extremely variable;
 - (b) For projects involving new radial circuits to connect to new or existing infrastructure, the £ per MW and £ per MW per km are also variable;
 - (c) The major infrastructure £ per MW is volatile; and
 - (d) Even if a bespoke revenue driver were constructed for each project, it would not provide timely funding of the investment.
- 2.18. Based on this analysis, we do not believe it will be possible to set a £/MW revenue driver that ensures the transmission licensees will be able to fund the necessary investments and protects the interests of customers. If the revenue driver were inadequate, then Ofgem would be failing in its duty to ensure that licensees are able to fund their activities. At the very least, there would need to be a guarantee that any shortfall in allowed revenue would be fully "trued up" at the next price control.
- 2.19. For the reasons set out above, we are firmly opposed to revenue drivers. Instead, we believe an ex-ante allowance for local generation connection work should be made, coupled with a "TIRG" type mechanism for major infrastructure investments including the island links. The only remaining alternative would be for a price control "re-opener" whenever a significant investment was planned.

Question 3.2: What factors should we bear in mind in drawing the boundary between fixed baseline revenue allowances and variable revenue allowances to be set through the revenue drivers?

- 2.20. If, despite the above analysis, Ofgem are still determined to introduce revenue drivers, we believe the baseline should be set on a central case forecast of the likely requirements. In SHETL's case this should include entry-triggered infrastructure work, and the "TIRG" type investments for the Dounreay – Beaully – Keith reinforcements.

Question 3.3: Should we seek to true-up the allowances generated by revenue drivers at the end of a 5-year control period? What factors should we take into account?

- 2.21. As noted above, a simple £/MW revenue driver is bound to be inaccurate. Depending on whether the number over or understated the efficient outturn costs, true-up would be required either to protect the interests of customers or to ensure the transmission companies receive adequate remuneration respectively. In our view, only a revenue driver linked to the particular investment needed and the capacity released would have sufficient accuracy to incentivise the transmission licensees and to minimise any true-up at the next price control.
- 2.22. However, this would clearly be onerous in terms of regulatory interventions, both in setting the price control and in dealing with amendments mid price control.

Question 3.4: When should we supplement the revenue drivers with other mechanisms to top-up revenue allowances in exceptional circumstances where major investment is needed? How might these other mechanisms work?

- 2.23. We agree with Ofgem that major transmission links to the islands of Scotland would certainly require bespoke allowances. However, other major mainland projects that are not sufficiently certain to be included in the RPI-X allowance may also require funding through such an allowance. The framework for such a mechanism already exists in the transmission licenses as the "TIRG" term.
- 2.24. We believe that this established mechanism should be used for these major projects. Our experience of the existing term to date would suggest that an appropriate time to set the incentivised capital expenditure allowance would be after the project had received the necessary consents, since only at this stage would the route be clarified and the costs more certain.

Question 3.5: Do you agree that, in the current market context, it is important to explore options to change transmission access arrangements? Do you agree with the process we have set out to progress this work?

- 2.25. The existing arrangements for transmission access are clearly not working efficiently in the context of the large volume of renewable generators now seeking connection to the system. The arrangements have been designed around the historic trend for large power stations that trigger increments in transmission capacity that are of an equal order of magnitude to the power station.
- 2.26. The current situation is that a small generator can trigger an investment in transmission capacity that is many times that required for the single generator. This "lumpiness" of transmission capacity has led NG to devise new arrangements for sharing the final sums liability. While this has helped to share the underwriting burden, it has also introduced a new level of volatility to final sums which in turn is creating uncertainty and risk for new generators.
- 2.27. A second problem relates to the queue for capacity that has developed in response to the Government's targets for renewable generation. This queue has projects at various stages of development and the prevailing methodology for allocation is that those generators that apply first get served first. This is, in our view, an irrational allocation of scarce capacity and there needs to be a more efficient, but proportionate, means to manage the queue and to promote those projects that are ready to connect.
- 2.28. We therefore welcome Ofgem's proposal to explore a lower and more stable level of commitment during the period before TEC is granted for new users of the system. We believe this will help to improve management of the queue in that only projects that are sufficiently well developed would be able to make such a commitment. Once connected, we believe that the existing arrangements embodied in the Grid Code and CUSC should be used to notify the system operator of capacity requirements and plant closures.
- 2.29. In particular, we are firmly opposed to any suggestion that existing parties should be required to make the same commitment as new users who drive investment requirement. Existing users who have been connected for more

than any proposed minimum TNUoS payment period would have made exactly the same commitment as new users.

- 2.30. Existing users are already obliged through the grid code to signal their requirements long-term to NG. To supplement this with a financial obligation would lead to two problems in particular:
- (a) Many generating stations that are near the end of their commercial life are not able to predict far enough ahead to be able to commit to many years TNUoS. An example cited at the 14th March meeting was Drax, which a couple of years ago might have struggled to commit for more than a year, but whose fortunes have swung around since. A rolling obligation might therefore cause premature closure of otherwise viable plant. Given the uncertainties on energy price, EU ETS and LCPD, a long term TNUoS commitment might be deciding factor in making a closure decision. The decision becomes more marginal the further north the generator is situated, since the TNUoS becomes more of a material issue in the economics.
 - (b) For the plant that can make such a commitment, the “X-1” years of TNUoS commitment becomes a sunk cost and the plant can continue to operate on a marginal basis until it becomes uneconomic to continue. In effect, the generator would be taking a decision each March whether to commit to a further year’s TNUoS, as at present. The generator is still able to take a short term decision to close e.g. following a major plant failure that is uneconomic to repair. Therefore the “signal” given to the system operator is only of limited value – there is still a risk that investment will have been committed on the basis of the X years underwriting.
- 2.31. It is therefore clear that such a commitment would not provide the information that the system operator is seeking and may also have unintended consequences in that otherwise viable plant might be forced to close early.
- 2.32. Furthermore, to impose a rolling requirement on all users would significantly add to overall costs (since there is a cost associated with providing letters of credit or assuming a balance sheet liability), which would have to be borne by customers. It could, for example, require existing generators to put forward credit for around £1bn which would significantly increase industry costs for no benefit.
- 2.33. Finally, while we support a user commitment model for *new* generators based on TNUoS charges, it is clear that this model will only work provided generators have certainty about the level of charges they are being asked to commit to (i.e. they cannot credibly be asked to sign a “blank cheque”). This is particularly important given the volatility of NGET’s TNUoS charging model and is another vital area of work that does not seem to have received significant attention to date. We would therefore urge Ofgem to finalise a mechanism for setting NGET’s TNUoS charges for the user commitment period. As part of that work, it will also be necessary for NGET to complete its review of the charging methodology, which was a condition of the approval of the TNUoS charges at BETTA go-live.

Other incentives – system reliability

- 2.34. We do not believe that the recently introduced interruptions incentive is appropriate or effective. We would however be firmly opposed to a "penalties only" scheme. Other things being equal, this would result in licensees earning less than the allowed cost of capital. As a consequence, at the very least, under a "penalties-only" scheme, the licensee would need to be granted an ex-ante allowance to compensate for the efficient level of interruptions (recognising that this is not zero interruptions). We believe that a more efficient scheme could be developed, based on a symmetrical interruptions incentive with equal prospect of reward or penalty depending on performance.

Other incentives – losses

- 2.35. We are disappointed that Ofgem have not considered the point raised in our previous consultation response regarding the possibility of a loss reduction incentive. The scope is possibly limited to the purchase of lower loss equipment in the case of the TOs but is nevertheless worthy of consideration.

3. Gas entry incentives

- 3.1. We continue to believe that the long-term entry capacity arrangements have not been successful in meeting the stated objectives of a long-term regime. Rather, we believe that the auction regime has distorted competition, unnecessarily increased perceptions of risk in operating in the competitive gas market and has required frequent, unanticipated regulatory intervention to solve problems that have emerged from the complex auction arrangements. We are therefore disappointed that Ofgem has not responded to the points we made in our reply to the second TPCR consultation in this respect.
- 3.2. Notwithstanding the above, we have responded below to the questions set out in chapter four.

NGG NTS'S OBLIGATIONS TO RELEASE CAPACITY

Question.4.1 - Do you agree with our plans to change the nature of NGG NTS's licence obligations to release entry capacity? What particular measures are needed to ensure that the regime is transparent, and ensure against capacity being held back unnecessarily?

- 3.3. Under the current regime, each entry point has a pre-determined baseline associated with it. This baseline has a dual role. It acts as a trigger in terms of NGG's NTS entry capacity incentive scheme. It also defines the amount of capacity that NGG NTS is obliged to offer for sale in the long and short-term allocation mechanisms. Ofgem's proposals for the next price control period would, we understand, still require baselines to be set at each entry point. However, unlike now, the baseline would only be used for the purpose of providing a trigger for NGG NTS's entry capacity incentive. It would not have any bearing on the amount of capacity NGG NTS would be required to offer for sale at these separate locations. Rather, NGG NTS would have a licence obligation to release all available capacity; an obligation to develop a transparent capacity release methodology; and to publish a network model to enable shippers to understand how the methodology is being applied.
- 3.4. In other words, if implemented, Ofgem's proposals would represent a significant change to the existing entry capacity arrangements and associated incentive scheme for NGG NTS. While we are generally in favour of reducing the complexity of the current incentive scheme, we are concerned that, as proposed, the regime would give far greater discretion to NGG NTS and greater uncertainty to shippers.
- 3.5. It would appear that Ofgem's proposals are based on the assumption that significant inefficiencies have resulted from the existing baselines due to capacity being sterilised at particular locations. However, we are not aware that any detailed evidence has been presented to illustrate this issue or quantify the extent of the inefficiencies the existing baselines have created.
- 3.6. We believe that the proposed approach would introduce considerable uncertainty to shippers as to the amount of capacity that would be made available at each entry point. We do not believe that the publication of a capacity release methodology statement coupled with a network model showing various scenarios would be adequate for shippers to make an assessment of the system capability at any one location. We are also concerned that Ofgem's proposals could undermine the commercial strategies

adopted by shippers since the introduction of the long-term entry capacity regime.

- 3.7. We are also uncertain how the proposed regime would interact with the application of revenue drivers. In particular, it would appear that the revenue drivers and capacity release mechanism would enable NGG to recover inappropriate incentive revenue. In our view, incremental incentive revenue triggered by a revenue driver should only reward NGG NTS for the provision of new investment. Indeed, this principle has been recognised in the proposed enduring exit capacity arrangements. However, under the proposed entry regime it would appear that NGG's discretion to, in effect, "move" capacity between system entry points would allow it to earn incentive revenue without any new, physical investment. This would unnecessarily increase bills for customers.
- 3.8. In our view, the discretion afforded to NGG under the proposed regime would risk inappropriate decisions being made by NGG in order to maximise its incentive revenue. The asymmetry of information available to NGG compared to Ofgem/shippers would make it virtually impossible for the latter parties to make an assessment of NGG's decisions of where and when to release capacity. We therefore believe that this is a fundamental issue with this proposal.
- 3.9. To summarise therefore, we are concerned that Ofgem's proposals in respect of NGG's obligations for the release of capacity would undermine the stability of the entry capacity arrangements and the associated commercial strategies adopted to date by shippers. We believe this could also undermine the confidence of existing and new market entrants and therefore, along with the uncertainty of what would be made available at any one location, it could create a further barrier to entry. We are also concerned that it could have an impact on the operation of storage facilities, which would not be in the interest of security of supply. Finally, we are concerned that the discretion afforded to NGG would add opacity to the regime that could provide opportunities for NGG to inappropriately gain under their incentive scheme.
- 3.10. To the extent that Ofgem believes the use of entry baselines has resulted in entry capacity being "sterilised", we believe there are other mechanisms that could be considered to resolve the issue. For example, at exit Ofgem is has proposed a mechanism whereby capacity could be transferred by substitution and with Ofgem's agreement. While this too has some issues associated with it, we believe that this would be more a transparent option for consideration. If Ofgem is to pursue the capacity release methodology proposal, we believe that it would be imperative that the initial methodology would have to be approved by Ofgem along with any proposal to change it thereafter.

Revenue drivers

Question 4.2 – Do you agree with our plans to refine how the revenue drivers work in cases where NGG NTS provides extra entry capacity, as requested by network users?

- 3.11. In order to reward NGG NTS for the provision of incremental entry capacity above the predefined baselines at each location, Ofgem has proposed that entry point specific Unit Cost Allowances (UCAs) would be retained. The

UCAs would be based on a return on the deemed cost of providing incremental capacity but fixed at the standard cost of capital, rather than a range of rates of return as in the current incentive scheme. Our understanding of Ofgem's proposals would mean that the money allowed through the revenue driver would fund NGG's investment for a fixed period of time providing NGG an incentive to beat the deemed cost. Thereafter, following a degree of reconciliation at the next price control review, the actual efficient cost would be allowed in the RAV.

- 3.12. We do not believe that the application of revenue drivers is an efficient or appropriate mechanism to fund NGG's incremental investment. As Ofgem has observed from the analysis set out in Appendix 10 of the document, incremental unit costs do not show a uniform relationship to the size of the flow increment. Furthermore, the revenue driver is highly dependent upon supply scenarios and supply substitution approaches. In other words, there is a significant risk of setting inaccurate revenue drivers. Inaccurate revenue drivers would result in NGG being over/under funded for the provision of incremental capacity, which could hinder the efficient investment in the system, particularly given NGG's discretion in this respect under Ofgem's proposals for capacity release.
- 3.13. We also note that the use of UCAs during the current price control review period has raised a number of issues. For example, we understand that by 2005 Ofgem was of the view that the UCAs set at the last price control review were incorrect. Furthermore, there has been a need to derive new UCAs for unforeseen new entry points, a feature that would continue under the proposed arrangements going forward.
- 3.14. In light of the above, and the issues associated with setting accurate revenue drivers that have been identified by Ofgem in Appendix 10, we believe that another mechanism should be considered for rewarding/funding capital expenditure associated with the provision of incremental entry capacity. This could be based upon the TIRG mechanism that already exists in the electricity transmission price controls. We do not believe that this would be any more onerous than Ofgem's existing involvement in "approving" NGG's release of obligated incremental entry capacity and in setting new UCAs as and when required. In our view, this would resolve most of Ofgem's concerns with setting correct capex allowances since those associated with smaller incremental amounts could, in our view, be dealt with in the time-tested manner associated with a traditional price control review – by setting an ex ante allowance.
- 3.15. Finally, given that the proposed UCAs would be based upon the deemed cost of providing *incremental* capacity, we do not believe that it is appropriate to use them as a means to set reserve prices for the sale of *existing* capacity.

Buyback incentive

Question 4.3 – Do you agree that changes are needed to the arrangements for buying back capacity rights, in particular to ensure a different sharing of risk between shippers, NGG NTS and consumers in respect of capacity which is dependent on large investment projects?

- 3.16. We have responded in more detail to Ofgem's proposals to, in effect, remove NGG's buyback exposure due to late delivery of incremental capacity from

the buyback incentive scheme currently in operation. While we understand the rationale to this proposal, (i.e. it protects customers from the potentially high cost of late delivery of new entry capacity), we are however concerned that a two-tier buyback incentive scheme would add further complexity to the regime. We are also unsure about the delineation between new and existing capacity and, therefore, where buyback costs would be allocated at existing entry points.

- 3.17. However, given the user commitment required to secure the provision of incremental entry capacity through the long term auctions, it would appear that NGG should be exposed to the cost of late delivery. Accordingly, we believe that there should be a market price for buyback rather than administered price, although we recognise that unlimited liability is not a realistic option.
- 3.18. From discussions to date, it would seem that the greatest risk of late delivery is associated with the consents and planning application process. Once projects have received all the necessary consents, the risk of late delivery is in NGG's control and, therefore, we believe that their exposure beyond the date of consent should reflect this. However, it would clearly be inappropriate to introduce an incentive scheme that did not encourage NGG to progress planning and consent processes proactively.

4. Gas offtake incentives

- 4.1. We continue to believe that wholesale reform of the NTS offtake/exit capacity arrangements is not required to address Ofgem's perceived issues with the existing regime. Our thoughts on this issue were set out in response to Ofgem's second consultation on the Transmission Price Control Review (TPCR) and have been made at the various Enduring Offtake Arrangements Working Groups (EOWG). We also set out in that response an alternative regime which we believe would better address the issues Ofgem have raised. We are therefore disappointed that Ofgem remain determined to progress with the enduring arrangements for exit reform as outlined in the previous consultation. We believe that the regime as proposed will increase costs to customers, distort competition and provide perverse incentives for investment.
- 4.2. We are also concerned that, to date, no consideration has been given to the enduring offtake arrangement incentive scheme that would apply to the DNs. The DN incentive scheme will determine the impact these reforms will have on these networks and therefore is a vital component of the proposals. We should stress that this aspect of the reform is of interest not only to the DNs but also to DN shippers.
- 4.3. Although there is already a DN incentive scheme in place for the transition regime, there are many aspects of it that would be unacceptable for an enduring incentive scheme. For example, a DN's exposure to variations in offtake capacity over which it has no direct control, such as genuine unforeseen demand growth and variations in CV. We are also concerned that a DN's exposure under the interim and transition incentive scheme is directly linked to NTS exit capacity charges that vary considerably between NTS charging zones. We therefore believe that there are many issues to be considered when devising the DN enduring offtake incentive scheme and, given its importance to the overall reform, we are concerned that this represents a significant part of the reforms that has yet to be considered.
- 4.4. Notwithstanding the above comments, we have responded to the questions set out in Appendix 12 below.

THE TRANSITIONAL REGIME

- 4.5. We agree with Ofgem that, in principle, the transition incentive regime for NGG should represent a continuation of the interim incentives already specified. However, we recognise that it would also be desirable, where relevant, to introduce elements of the proposed enduring incentive regime to the transition period. We believe this would aid simplicity and transparency while providing greater stability within the regime for the whole price control period.

Revenue drivers and baselines

Question A12.1 – Do you agree that for the period from 1 April 2007 to 30 September 2010, baselines should: a) not be specified for interruptible capacity; b) not be specified for GDN flexibility; c) be at the same level and degree of aggregation as during the enduring period (i.e. nodal and based on practical maximum physical capacity)?

- 4.6. Ofgem has described that baselines for the transitional period would perform a single function as a high level delineation between TO funding and remuneration of incremental investment. In other words, the baseline would define the prevailing National Transmission system (NTS) network capability. Where National Grid Gas (NGG) provides NTS exit capacity over and above the baseline quantities in response to requests received from either a Distribution Network (DN) or a Transmission Connected Customer (TCC), NGG would be able to recover additional allowed revenue in accordance with the proposed revenue driver mechanism.
- 4.7. Providing NGG is not to be remunerated through the revenue driver scheme for meeting additional requests for NTS exit capacity that is within the capability of the *existing* network, it would seem appropriate to set the transition baselines on a maximum practical physical basis.
- 4.8. Ofgem has proposed that, contrary to the existing price control, predefined baselines would only be set for firm NTS exit capacity. That is, no interruptible baselines will be set. Since the purpose of the baseline in the transitional regime is to trigger incremental allowed revenue for NGG where additional investment has been made on the system, and since no investment is made to deliver interruptible capacity (rather it is a by-product of a non-peak day) this approach seems appropriate. However, to avoid confusion, we believe that it is important for Ofgem to clarify that existing interruptible exit points will continue to have access to the NTS for the offtake of gas.
- 4.9. We agree with Ofgem's view that for the transition period, baselines would not be set for NTS flexibility exit capacity. This is because NGG has so far been unable to define exactly this product physically or the relationship between flat and flexibility capacity. We believe that there is a significant amount of uncertainty surrounding this product and therefore, it would be inappropriate to set a baseline before the product is sufficiently understood. Furthermore, we understand that flexibility has traditionally been provided as a by-product of flat capacity and NGG has not indicated that there will be any difficulty in meeting requirements for the transition period.
- 4.10. We agree that it would be appropriate for the transition baselines to be set on the same basis as those that will apply to the enduring period. That is, on a nodal basis and to reflect the practical maximum physical capacity.

Revenue drivers

Question A12.2 – Do you agree that incremental investment should be remunerated throughout the entire duration of the next price control period through the application of pre-specified revenue drivers?

- 4.11. As we have explained in the relevant section under the enduring regime below, we do not support the application of pre-defined revenue drivers. However, to the extent that they are deemed appropriate following the

outcome of the TPCR consultation process it would seem appropriate that they apply for the duration of the price control period rather than just the transition period. This would avoid the potential for having two incentive schemes within the price control period.

Transitional incentives

- 4.12. While we welcome the initiative to simplify the incentive regimes that would apply to NGG, it will be important to ensure that NGG's behaviour in the transition period in terms of efficiency is not compromised as a result.

Question A12.3 – Do you agree that the charges foregone and investment incentive should: a) not apply for the transitional period; b) be removed for the period from 1 April 2007 – 30 September 2008?

- 4.13. Our understanding of the charges foregone and investment incentive is that it was, in essence, introduced to encourage NGG to minimise the interruptible discount and reward incremental investment above the baselines. We understand that a key element of the scheme was the anticipated reform of interruption arrangements at the time it was introduced. However, as this did not materialise, the caps and collars associated with this aspect of the scheme were reduced to £1m from 04/05 which considerably reduced NGG's scope for reward. Since this aspect of the scheme has, therefore, limited impact on NGG and the proposed new incentive scheme would, we understand replace it, we believe there are grounds to remove it for the next price control period.

Question A12.4 – Do you agree that the constrained LNG incentive should a) be retained for the transitional period; b) apply to the enduring period? Qu A12.5 – What do you believe is the appropriate level for the constrained LNG target for the formula years 2009/10, 2010/11 and 2010/12?

- 4.14. We believe that it is important to retain the constrained LNG incentive on the grounds of NGG's ownership of the LNG storage facilities. We note from NGG's incentive scheme performance report that in the last two years it has benefited under the scheme by £3.9m and £5.4m against targets costs of £6.2m and £6.6m. We therefore believe that it would be appropriate to set more stretching targets going forward.

Question A12.6 – Do you agree that all buyback costs should be treated as excluded revenue within the transitional period

- 4.15. During the transition period NGG will continue to have rights to reduce offtake capacity to existing NTS users for up to 45 days. We therefore agree that no buyback related costs should be allowed as part of the price control settlement for the transition period.
- 4.16. The structure of the current ARCA allows NGG some protection from late delivery of incremental capacity. However, we believe the protection afforded to NGG under the ARCA for late delivery of capacity is inappropriate given the level of commitment a User has to give under the same agreement and the implications of late delivery. We therefore believe that this aspect of the ARCA should be changed. At the very least, while this

provision prevails we believe that NGG should be fully exposed to buyback costs associated with the late delivery of incremental NTS exit capacity.

Question A12.7 – Do you agree that the greater than 15 day interruptions incentive should be retained? Qu A12.8 – What are your views on the appropriate level of the target, cap and collar for the greater than 15 day interruption incentive.

4.17. We support the retention of the 15-day interruption incentive for the transition period. NGG's incentive performance report indicates that in 2002/03 the cost to it under this scheme was £0.1m against a performance target of £2.8m. No detailed analysis on this particular aspect of the scheme is given for the subsequent two years, so it is difficult to provide a precise comment on where the target should be set going forward. However, the first year's performance would suggest that more stretching targets should be set.

THE ENDURING REGIME

The importance of user commitment models

Question A12.10 – Do you agree that our emphasis on user commitment is appropriate?

4.18. While we believe that an element of user commitment may be considered desirable in the enduring regime, we are concerned by the level of emphasis that is being placed on this aspect of the model. Clearly, it is appropriate to ensure that the risk of assets being stranded is minimised as far as possible. However, we remain concerned that Ofgem's defined user commitment model has a number of significant issues associated with it, which are set out below.

- In effect, the proposed user commitment model simply transfers NGG's investment risk onto TCC and DN Users. We do not believe that this is appropriate. DNs in particular (as regulated monopolies) should not be required to bear all of the investment risk of another regulated monopoly, the NTS. Furthermore, we believe that a transfer of risk from the regulated monopoly to TCCs and their shippers of the scale proposed could have a significant and detrimental impact on competition.
- We do not believe that existing Users would be in a position to make an extensive financial commitment to maintain guaranteed access to current levels of offtake. Many existing TCC's continued operation will be on a marginal cost basis. A significant change to the costs/liabilities they are exposed to going forward could impact the economics of this marginal plant and potentially force early closure. In other words, the extensive user commitment model proposed by NGG means that capacity charges would no longer be a relatively stable and "boring" element of the commercial regime. It would instead represent a significant, new liability on the balance sheet for existing users, which could prematurely force plant off the system. In addition, some TCC/shippers would be forced to rely on the medium and short-term allocation process. This would not be in customers' interests and could be detrimental to supply competition. It would also mean that NGG would not receive the long term investment signals or details of User requirements.

- We also believe that any model which requires users to make a firm, forward-looking user commitment will only be possible provided such users have certainty over the liabilities to which they are committing. This means that users will need to know the future use of system charges they would be required to pay for the period of their commitment.
 - An extensive user commitment model is also likely to have an impact on shipper/supplier competition given the interaction of TCCs and shippers. That is, we believe that smaller shippers will be less able to manage the liabilities of a user commitment model thereby hindering their existing position in the market and/or acting as a barrier to entry.
 - We also believe that there could be a risk that a commitment to pay would not necessarily equate to an existing User's future use of capacity. Indeed, the longer the commitment period for an existing User the weaker the correlation. This is because the continued operation of, say a chemical or generation plant is based upon a marginal cost basis. If at any one time the forecast revenue does not cover these marginal costs the plant will close irrespective of any commitment it has given to the NTS. In these circumstances the commitment of the User to pay will not have given NGG any better information on the likely use of that User of NTS exit capacity than would have been received under the prevailing arrangements.
- 4.19. By contrast, new Users or existing Users requesting incremental capacity are in a different position. This category of User would be in a position to commit to a number of years of charges for the new capacity that was being requested since that level of access (and the commitment to pay for it) would be an integral part of their business model and would have been factored into any financial modelling behind the capacity request.
- 4.20. We therefore believe that the primary focus of Ofgem's user commitment model should be limited to a User's request for *incremental* NTS exit capacity above the baseline. This would apply equally to existing and new Users requests for incremental capacity. We also believe that a requirement to commit for nearly seven years is excessive. We consider that a one or two year commitment would be sufficient.
- 4.21. Turning now to DNs. The ability of a DN to take on a level of user commitment, which is in effect the NTS load related capex investment risk, would depend entirely on the DN's price control settlement and there has been no discussion on these matters. Therefore, until this key component of the proposed regime has been resolved, DN's will be unable to accept a user commitment model.

Product definition

- 4.22. We note that Ofgem continues to support the view that all Users, i.e. TCC and DN Users should be offered the same set of offtake capacity products and on the same terms. In addition, as discussed above, Users should signal their requirements for offtake capacity and provide a commitment to its use.

- 4.23. Ofgem also continues to believe that there should be both flat and flexibility offtake products. We believe that there are a number of complex issues associated with the flexibility offtake capacity product that have yet to be resolved and we are concerned that the introduction of a separate flexibility product for all Users adds considerable complexity to the exit arrangements.
- 4.24. One of the most complex issues that has yet to be resolved is the relationship between flat and flexibility capacity since they are usually provided by the same assets and investment for each is inextricably linked. Whilst the 1 in 20 planning and development standard currently focuses on peak aggregate daily demand for flat capacity and requirements for within day flow variations or flexibility capacity on the same day, current proposals which separate both products focus on independent peak requirements. We believe arrangements should recognise that peak requirements for flex will occur at times when peak flat capacity is not being utilised, i.e. there is an inherent capability for flex within the network. If NGG were to invest to provide peak requirements for both flat and flex capacity independently this would be a significant departure from current standards that would result in substantial over-investment.
- 4.25. We therefore agree with Ofgem's view that NGG's proposals for an "expanding flexibility" or a single "transmission capability" product could have considerable merit. While we would welcome a move that would simplify the enduring arrangements, the lack of analysis available to us on the proposed relationship between the two products makes it impossible for us to comment further on the most appropriate option. We would therefore urge Ofgem/NGG to bring forward the requisite analysis on the relationships between flat and flexibility capacity as a matter of urgency. We would certainly expect the conversion factor (or gradient of the line) to be considerably more than zero.

Allocation mechanisms

- 4.26. Notwithstanding our earlier comments on the issues associated with the user commitment model, we are encouraged that Ofgem's initial view is that a prevailing rights model is worthy of further development and consideration as a mechanism for introducing user commitment. Under this model, existing users' prevailing rights to capacity would continue. In our view, this approach would potentially overcome some of the issues associated with the user commitment model highlighted above as long as a user does not wish to alter its capacity requirements. Accordingly, we welcome the development by NGG's of a prevailing rights strawman.
- 4.27. However, we are concerned that, at this stage, NGG's proposals would require an existing user to commit to nearly seven years of capacity charges on its prevailing capacity bookings as soon as it requests even the smallest level of incremental capacity, irrespective of whether incremental *investment* is required. That is, a commitment to pay for the four years required to give NGG its investment signal; plus, thereafter, the two and a half years' notice period/commitment.
- 4.28. We believe that this level of commitment is unacceptable for both TCC Users and DNs and is unjustified by NGG. Certainly, we do not agree that a two

and a half year “notice period” to reduce capacity holdings is appropriate. Instead, we can see no justification for existing users moving from an annual commitment to capacity. In particular, we do not believe that existing customers will really be in a position to effectively commit to remaining connected for three years. We also fail to see why NGG would need a prevailing booking for four continuous years to secure incremental exit capacity, particularly if that capacity could be provided without the need for investment. We consider at most that a commitment to pay use of system charges for two or three years after connection should provide sufficient certainty to NGG. Furthermore, if capacity is available we believe that it would be inefficient not to allocate it in the longer term if a party has signalled that it is required, albeit for a period of less than four years.

- 4.29. As proposed, capacity would only be allocated for 12-month strips and this would only occur once a year. Under this proposal, there is a potential risk that Users would be forced into committing to capacity for a longer period than is actually necessary. For example, if incremental capacity were required for use in May a commitment for capacity from the previous October would be required. Similarly, if a User’s profile of capacity use is not constant across a twelve-month period, e.g. at storage sites, the ability to only book an annual tranche could potentially create inefficiencies and increased costs.
- 4.30. While we recognise that a higher degree of granulation introduces further complexity, we nevertheless believe that further consideration is required on this aspect of the proposed allocation mechanism. This point was discussed at EOWG on 19th April and there was a suggestion that the former point could be addressed through some form of “side agreement”. While we would welcome a resolution to the problem it illustrates that the proposed reform introduces new complexities and issues. This is particularly the case for storage sites which is a concern given the strategic importance of storage in terms of security of supply.
- 4.31. We note that under NGG’s strawman, capacity in the constrained period would be allocated on a pay-as-bid basis. We are disappointed that a volume-based allocation has not been considered where there are competing bids for capacity. We agree that NGG should have an obligation to allocate any unsold baseline capacity. However, in our view, this obligation should also apply to the release of capacity on the day.

Consideration of the high level options in the Second Consultation

Question A12.11 Do you agree with our assessment of the high level options in the second consultation? A) Do you agree that NTS exit capacity products should be specified on a nodal basis? B) Do you agree that baselines should be specified on a nodal basis? C) Do you agree that NGG NTS should be subject to a substitution incentive?

- 4.32. We agree with Ofgem’s view that a model of offtake arrangements based on a nodal product and nodal baseline is most appropriate when compared to the various zonal models outlined in the Second Consultation. In our view, a nodal model is more transparent, less complex and is likely to secure more focused investment information for NGG. However, once capacity has been allocated it will be essential to ensure that the commercial and operational

regime does not restrict the existing efficient use of capacity between nodes and the efficient operation of the network.

- 4.33. We also support Ofgem’s view that a substitution incentive is not appropriate. In our view, it would be inappropriate for NGG to receive additional incentive revenue for capacity that is already on the system. We also believe a substitution incentive would add unnecessary complexity.
- 4.34. We note instead that Ofgem has proposed the introduction of a substitution obligation. We believe that this would be consistent with the efficient and economic development of the NTS and, therefore, one would expect NGG to optimise the use of capacity across the network in the normal course of events.
- 4.35. However, we are concerned that Ofgem believes that where substitution has taken place, there should be corresponding changes to the associated baselines. In our view, this inappropriately transfers further risk from NGG to the Users of the system and creates added complexity through the introduction of exchange rates etc. We would also consider it inefficient if, for example, a User signalled three year’s sustained use for baseline incremental capacity at one location but, due to it being less than the required sustained booking of four years, capacity was not allocated and instead, that capacity was substituted at a less than one-to-one ratio to another location where a four-year signal had been given. We therefore believe that in the event that NGG were intending to initiate a change to the baselines through substitution, Users should be notified beforehand and provided with an opportunity to revise their applications prior to any substitution being agreed to by Ofgem.
- 4.36. We are also not clear how the proposals in relation to substitution relate to the concept of a baseline set on practical maximum physical availability. In particular, we had understood that the main difference between theoretical maximum physical capacity and *practical* maximum physical capacity was that the latter took account of possible substitution between nodes. As a consequence, if Ofgem proceed on the basis of a practical maximum physical, we do not understand why any separate mechanism for substitution is required.

Interaction of user commitment models with 1 in 20 obligation

Question A12.12 - Do you agree that NGG NTS should only be remunerated for incremental investment to the extent that there is an associated user commitment?

- 4.37. We do not agree with Ofgem’s proposal that NGG would only be rewarded for incremental capacity where there is an associated user commitment. Investment should be rewarded as long as it is efficient. As proposed, in situations where investment is “lumpy”, NGG would only be remunerated for the capacity assigned to the User, the remaining part of the minimum increment of capacity would appear not to be funded despite it being efficient. We therefore believe that if this approach were to be adopted, it would be more appropriate to reward NGG for efficient investment *driven* by user commitment. If this is not the case, there is a risk that NGG will be incentivised to deliver sub-optimal investment in the network.

Question A12.13 - Do you agree with our minded to position with regards to compliance with the 1 in 20 obligation?

- 4.38. Ofgem has offered an interpretation of how, under the proposed user commitment model, NGG would meet its 1 in 20 obligation. That is, NGG will be deemed to have met its 1 in 20 obligation provided it has invested in line with user commitments which signal peak aggregate daily demand. This guidance is based on the principle that DNs would book their 1 in 20 requirements in order to satisfy their own obligations and TCCs would book their peak demands to ensure their right to flow gas to meet their own needs.
- 4.39. While we agree that the above approach would be important in assessing NGG's compliance with its 1 in 20 obligation we do not believe that it would be absolute. In particular, we are concerned that this approach would in effect absolve NGG entirely of its investment responsibilities other than reacting to other parties' information provision. We do not believe that this would be appropriate given the diverse nature of Users and their ability to provide commitment and finance risk; the range of criteria used to determine a Users' capacity requirements; margins of error; load diversification; and other factors that could influence capacity requests and investment scenarios. We are also concerned that in adopting this approach there is an assumption that there is a linear relationship between demand and investment; and that estimating 1 in 20 requirements is an exact science. We therefore believe that, in its role of owner and operator of the NTS, NGG should take more responsibly for ensuring compliance with its 1 in 20 obligations than suggested by Ofgem's dependence on the user commitment model.

Question A12.14 - Do you believe that there should be any pre-conditions before incremental investment is remunerated e.g. consideration of opportunities for long term buyback contracting, delivery of the investment?

- 4.40. It would clearly be efficient to ensure that NGG considers other options available to it to meet incremental demands for exit capacity such as long term buyback tenders. We agree that Users should not pay for the incremental capacity until it becomes available, i.e. NGG has delivered the investment. However, we believe that this approach could mean that a further mechanism would be required to fund the construction period up to the point of delivery to alleviate cashflow/financing issues. While we believe this issue has to be addressed, it illustrates once more how the introduction of this reform creates additional issues that must be resolved all of which adds additional layers of complexity to the enduring arrangements which are already significantly more complex than the existing arrangements. These issues also increase the risk of unintended consequence arising from the reforms.

Baseline derivation

Question A12.15 - Do you agree that the level of baseline should be determined in accordance with the practical maximum physical capacity of the network?

- 4.41. We have a number of concerns with Ofgem's proposals for applying an incentive mechanism that revolves around predefined baseline quantities and the application of a revenue driver to reward incremental investment. More detail on this is highlighted below in the section on "Revenue drivers".

Notwithstanding these issues, we have provided our comments on the proposed baseline issues below.

- 4.42. Under the enduring arrangements, the baseline serves as a trigger for rewarding NGG for incremental investment as well as defining obligations for capacity released up to that baseline level.
- 4.43. We therefore believe that it would be a pragmatic approach to set the nodal baselines in accordance with the practical maximum physical capacity of the network. However, it will be necessary to ensure that these baseline levels truly reflect the physical capability of the system to ensure that NGG is not rewarded for capacity that is already there.
- 4.44. For example, from the indicative numbers provided, a practical maximum physical baseline would mean that, in some instances, existing interruptible sites would have a firm baseline associated with it although this capacity would not be allocated to the site unless it was purchased through either the long term or short term allocation mechanisms. That is, there would be no “prevailing right” of either firm or interruptible capacity at these sites. Setting baselines against the practical maximum physical capability of the network would, therefore, ensure that NGG is not inappropriately rewarded for releasing firm capacity at these sites.
- 4.45. Nevertheless, setting accurate baselines will not be an easy task and will be dependent upon a number of assumptions. Considerable due diligence will therefore be required to ensure that NGG does not propose baselines that underestimate the capability of the system. Therefore, if agreement cannot be reached, a theoretical maximum physical baseline may be more appropriate. We note that Ofgem has asked for feedback on the baseline numbers contained in Annex 1 of Appendix 12 and we have done this separately noting in particular where on a number of occasions the baseline would appear to be less than we would expect.
- 4.46. Notwithstanding the above, it is evident that the proposed enduring arrangements will have an impact on existing storage sites. We note that both Ofgem and NGG have an outstanding action to consider further the interactions between entry and exit capacity at these sites. For example, where the long-term entry capacity regime has been used to provide firm access to the NTS, we question why there is not any associated firm exit capacity given that the investment has been funded by the entry capacity regime. We suggest that this needs to be addressed as soon as possible to alleviate the current uncertainty, given the importance of such facilities.

Question A12.16 - Do you agree that baselines should be static throughout the price control period?

- 4.47. We do not believe that it is appropriate to have a static baseline for the price control period since we believe that some investment will already have been funded by the existing price control for delivery sometime beyond 2007. We therefore believe that the baseline should reflect the investment that has already been committed and provided for and the time that it will be delivered.

Revenue drivers

Question A12.17 – do you agree that revenue drivers are an appropriate tool for remuneration of incremental investment?

- 4.48. We understand the rationale behind Ofgem’s proposal to introduce mechanistic revenue drivers as a means to fund NGG’s load related investment over and above the defined baseline quantities. However, we are concerned that the benefit of a mechanistic approach is only achieved to the extent that the revenue drivers themselves are 100% correct in all scenarios. Failure in this aspect would inevitably introduce a degree of over/under investment (and potentially revenue recovery) and, therefore, economic inefficiency. Indeed, Ofgem’s preliminary observations on NGG’s analysis of potential entry revenue drivers set out in Appendix 10 illustrates the difficulties in deriving accurate revenue drivers.
- 4.49. As far as the enduring exit arrangements are concerned, we believe that this issue would become far more significant if baselines and revenue drivers were to be determined for both flat *and* flexibility exit capacity. This is because in most cases the two “products” would be provided by the same physical assets and are inextricably linked. We recognise that some of this interaction may be accounted for if an “expanding” flexibility or a single “transmission capability” product was to be introduced.
- 4.50. At a recent EOWG meeting we were led to believe that some of the existing NTS exit capacity has arisen due to investment at entry. It would therefore be important to understand this in more detail since a situation could arise whereby NGG could release incremental exit capacity that has been provided as a result of entry investment. While we would expect NGG to release any capacity that is made available in this way, it would clearly be inappropriate for it to receive incremental revenue for this associated capacity through the exit revenue driver (i.e. for the investment to be funded twice).

Question A12.18 – Do you agree that the appropriate form of revenue driver is a) zonal revenue drivers for small capacity increments; b) project specific revenue drivers for large anticipated projects; and c) licence modifications in the event of unanticipated investments which exceed a specified threshold or projects at new exit points?.

- 4.51. Ofgem has proposed that in addition to creating a zonal revenue driver for small capacity increments, project specific revenue drivers would be set for those large projects which are currently anticipated. Furthermore, where unanticipated projects arise within the price control period that do not “fit” the relevant zonal revenue driver a new one would have to be created and inserted into the licence. We believe that this approach should help to address the issue of creating accurate revenue drivers for these large projects as it would enable forecast project specific costs to be back-engineered into a revenue driver. However, the issue of how to set appropriate zonal revenue drivers remains. We are also unsure how the threshold would be set to determine whether a zonal revenue driver would apply or that a project specific one was more appropriate.
- 4.52. Although Ofgem’s proposals indicate that the revenue driver would be applied from the point of investment delivery there is no further detail on the incentive scheme. For example, for how long would the revenue driver apply? Is it a

rolling incentive mechanism whereby after say, 5 years, an assessment of the actual investment cost is made and the efficient investment expenditure is then incorporated into the RAV? We would ask Ofgem to clarify this point and certainly we would expect there to be a truing up mechanism at the next price control review.

Question A12.18 – Do you believe that revenue drivers should be indexed with respect to the price of key inputs such as steel?

- 4.53. If revenue drivers are to be set we believe that it would be appropriate for them to be reflective of the key inputs.

Proposals for buy-back incentive

Question A12.21 – Do you agree that, with respect to buyback: a) investment related buyback costs should be treated as excluded revenue and subject to an administered price? b) the costs of buybacks in the event of a planned and unplanned outages should be subject to a sliding scale incentive regime?

- 4.54. As we understand it, Ofgem’s proposed user commitment model would, in effect, transfer the risk of forecast demand patterns and associated investment decisions from NGG on to users of the system. That is, users would be required to determine when and how much incremental capacity they would require and, to the extent that NGG makes the capacity available, provide a long term commitment to pay for it. Clearly, the corollary of this is that in the event that NGG does not meet those commitments it should be exposed to that risk. We also note that the consequences of late delivery for Users is likely to be significant, especially for DNs where there are likely to be limited alternative investment decisions to meet their requirements at “short notice”. As a consequence, we suggest the greater the users’ commitment under this model the greater the risk that NGG should be exposed if it were not able to meet that commitment.

Question A12.22 – What is your view in relation to: a) the extent of flexibility that NGG NTS should have over investment lead times; b) whether there is merit in implementing a cap on the total exposure associated with any individual, investment related, buyback action at exit; and whether operational buyback costs should also be subject to an administered price.

- 4.55. Given the above, we believe that Ofgem’s proposal is perhaps correct in that it would ring-fence the revenue and costs associated with the delivery of incremental capacity. This would ensure that any costs incurred due to late delivery of incremental capacity would not be transferred to customers. It would also suggest that NGG should be exposed to the market cost of buybacks (for both late delivery of investment and operational buybacks for existing capacity) rather than an administered price although we do believe that some sort of cap would probably be appropriate. We do not share Ofgem’s concern that key Users could try and extract inappropriate buyback fees from NGG. If Ofgem considers this to be a real issue, we would suggest that there is a fundamental flaw with the model being proposed.
- 4.56. Notwithstanding the above, we are concerned that the introduction of a two-tier buyback incentive scheme would introduce even more opacity and potential complexity to the regime. For example, how would incremental

capacity be distinguished from non-incremental capacity where new investment is carried out at existing exit points? Certainly, if this proposal is to be progressed, more clarity will be required in respect of the various types of buyback, how they would be identified from each other and accounted for within the schemes. We are also unsure of how the regime would work given Ofgem's suggestion that terms for buyback may be altered through bilateral arrangements – when would this happen? Ofgem also suggests that NGG should be able to alter lead times on a project specific basis – again, at what point would this happen, before or after a User has participated in the long term allocation mechanism? Either way, we do not understand how this would interact with the model that is being proposed (which is based on a predefined constrained period).

- 4.57. As a consequence, it would seem that in order for Ofgem's proposals for the enduring arrangements to work, an increasing number of "carve outs" and /or caveats are being considered. We believe that these issues will lead to unintended consequences and the need for repeated intervention by Ofgem mid-price control, which undermines the original rationale for the scheme.

Payment flows

- 4.58. To the extent that it is deemed necessary and the benefits of doing so are demonstrated to be material, we believe that a move to the DN charging model should coincide with day one of the enduring regime and not before. However, as we have already stated, the nature of the DN incentive scheme will be key to this payment arrangement and until those discussions begin it is difficult to comment further at this time.

Other issues

- 4.59. Ofgem's view (set out in paragraph 1.161 of Annex 2 to Appendix 12) that the costs incurred by the GTs (and the Agency) in meeting the licence obligation to implement the enduring offtake arrangements is unacceptable. This was not agreed as part of the DN sales process.
- 4.60. Irrespective of this, for Ofgem to suggest that GT licensees should have to fund, at their own expense, activities associated with proposed Ofgem reforms of the NTS is, in our view, unsustainable.

5. Expenditure analysis: Capital expenditure

Question 6.1: Do you have any comments on our approach to assessing historic and forecast capex? Are there any other factors we should take into account?

- 5.1. We agree that the analysis of historic costs should include a review of the planning processes and an assessment of the efficiency of sample schemes. It is also important to review the factors influencing the differences between actual capex and the forecast at the time of the last review. For example, re-engineering of individual schemes resulting in efficiency, innovation, or deferment of capital expenditure.
- 5.2. We also agree that it would be appropriate to use similar approaches for analysing the forecast capital expenditure. This is more relevant in the case of non load-related capex since it is closely linked to the asset risk management policies and procedures. In this context, we welcome Ofgem's proposal to establish a workstream to analyse asset management systems.
- 5.3. In respect of load-related expenditure it will be important to establish a baseline of investment that will be required under all foreseeable scenarios.
- 5.4. We have recently been experiencing unprecedented increases in commodity prices such as steel and copper and these have been feeding through into equipment prices such as transformers. Additionally other costs have increased significantly, possibly due to supply and demand issues driven by major construction projects and other infrastructure investments. In any event it is clear that the analysis of forecast capex should also take into account such price variations and include measures to deal with the volatility, possibly through price indexation other than RPI. It should also include the impact of the revision of connection boundaries, in particular the change to a "shallow" connection policy in SHETL pre BETTA, and the introduction of the very shallow "Plugs" approach post BETTA.

Question 6.2: Should some degree of alignment be adopted for capitalisation of forecast costs across the transmission licensees, or should, especially in the case of the Scottish licensees, the approach be consistent with DPCR?

- 5.5. We agree that a consistent approach to capitalisation policy might be desirable, but the businesses are significantly different in scale and balance of work. This means that it would be legitimate and appropriate to have differing percentages of indirect costs capitalised between the companies.

Question 6.3: Should some adjustment be made to network flexibility margins, particularly for the NTS 5% planning flow margin?

- 5.6. Since National Grid is responsible for providing adequate capacity on the gas transmission system, it is for them to demonstrate that a flow margin continues to be necessary despite the mitigating effects mentioned in paragraph 6.23. To the extent that NG are able to demonstrate the requirement, then this should be allowed in their forecast capital expenditure requirements.

Question 6.4: In carrying out cost-benefit analysis to assess the efficient level of transmission capacity to accommodate wind generation, what new factors need to be taken into account?

- 5.7. A key distinction to be taken into account is that the specific investments to connect new generators to the transmission system are now classed as "sole use infrastructure" under National Grid's charging methodology, rather than connection as was the case in the pre-BETTA arrangements. The forecast expenditure for these sole use assets amounts to £70m for SHETL.
- 5.8. In previous price controls, connection costs were largely irrelevant in price control terms, since the expenditure would have been offset by matching customer contributions. This means that the revenue automatically adjusts to match whatever connections actually proceed. There was therefore no need for Ofgem to set a revenue allowance for the expenditure, (since it would be paid directly by the user).
- 5.9. In this price control Ofgem will need to determine a revenue allowance for this local infrastructure. However, the efficient level of investment is determined by the minimum size of project to cater for the generator's requirements consistent with the GBSQSS, rather than the generator's willingness to pay the connection charge as was previously the case.
- 5.10. Factors affecting the design will include whether the generator had previously accepted an offer under the pre-BETTA arrangements.
- 5.11. The main infrastructure reinforcements are driven by the cumulative effect of new generation increasing power flows over the network. The reinforcements are required to maintain compliance with the GBSQSS and are subject to the technical and economic efficiency tests embodied in the standards.
- 5.12. Our proposed mechanisms for setting revenue allowances for these various elements are set out in section 2 above.

Question 6.5: What would be the most appropriate approach to restoring the incentives for relevant parties to reach the most cost-effective connection design? How should the TPCR allowance take into account the various solutions?

- 5.13. The connection charging arrangements introduced with BETTA, combined with applying the GBSQSS to the 132kV system in Scotland have led, in our view, to network designs which are more robust than has previously been considered adequate.
- 5.14. In particular, when a new generator had to pay for a new 132kV transmission line, and a new substation, the design almost invariably consisted of a single circuit spur and a single transformer substation. Under BETTA, the GBSQSS require that the circuits are duplicated and, since the assets are treated as infrastructure, there is no financial incentive on the generator to accept a lower standard of security. Indeed, the use of system charges to which the generator is liable are based on a fully duplicated connection and there is no facility to choose a lower charge to compensate for reduced security.
- 5.15. This causes two key problems. Firstly, generators who have accepted a connection offer based on the pre-BETTA charging arrangements are discriminated against compared to generators who have received an offer based on GBSQSS. They pay an identical use of system charge, but receive a

lower standard of service. In effect, the economic benefit that these generators (and ones already connected) chose in agreeing to pay for a single circuit rather than a double circuit has been removed, and distributed among other users through lower use of system charges than would have been the case if the network had been fully duplicated.

- 5.16. Secondly, there is no reason to suggest that a single circuit connection would not be acceptable even for new generators provided that they received the appropriate cost signal and could decide on a level of security consistent with their requirements. This would ensure an economic level of investment and restore the incentives to reach an economic design.
- 5.17. We believe that the most appropriate way to restore incentives to reach the most cost-effective network design is to charge for the 132kV network connections and TNUoS in the same way as for distribution connections.
- 5.18. This would remove the artificial distinction between the 132kV system voltage. Ideally, this should be done by redefining the Scottish 132kV system as distribution in the licences. However, since this would require primary legislation, it might not be a proportionate response to the problem. At the very least, we believe that only the 275 and 400kV "supergrid" should be included in National Grid's charging methodology, including the locational security factor (to the extent that this is still considered relevant after NG's review of the methodology).
- 5.19. The costs of the Scottish 132kV system should be separately identified for the two Scottish transmission licensees and charged on a similar basis to the E&W 132kV system.
- 5.20. These two measures would solve a number of problems with the current arrangements:
 - The incentive for (and benefit of) an economic connection design would be returned to the generator;
 - All generators would pay TNUoS on firm (supergrid) transmission capacity; and
 - The discriminatory charging arrangements between generators connected at 132kV in England & Wales as opposed to Scotland would be removed.

Treatment of Capex to support operational efficiency

- 5.21. Ofgem has proposed in paragraph 6.37 of the consultation that it may be more appropriate for National Grid as GBSO to co-ordinate the trade off between network investment costs and SO costs across the whole GB system. Such a proposal would, in our view, undermine the whole rationale of the BETTA arrangements.
- 5.22. A fundamental requirement of any business is the ability to make investment decisions. A particular feature of the BETTA arrangements was to set up a framework of information exchange under the auspices of the SO-TO Code (STC) to enable all the transmission licensees to co-ordinate efficient investment in the transmission system. The BETTA framework has only been in operation for just over a year, and was constructed by the licensees and Ofgem with Ofgem's full knowledge of the importance of retaining investment decisions within the respective companies.

5.23. Ofgem's proposal is to "include the remuneration for such investment directly within the GBSO's incentives and to let it contract with the Scottish TOs for delivery." In light of Ofgem's full involvement in developing the BETTA arrangements, we consider this a surprising development and we would be firmly opposed to simply acting as National Grid's contractor for transmission investment. This has been made clear on many occasions during the BETTA process.

6. Expenditure analysis: Operating expenditure

Question 7.1: Do you have any comments on our approach to assessing historic and forecast opex? Are there any other factors we should take into account?

- 6.1. We recognise the difficulty of undertaking comparative assessment of the transmission businesses due to the limited number of comparators. However, we are extremely disappointed with the superficial time series analysis carried out by Ofgem. The analysis grossly distorts the productivity improvements of SHETL because it appears to have been carried out using the whole operating expenditure of SHETL, much of which was fixed and uncontrollable.
- 6.2. SHETL has a very low base of controllable operating costs. Prior to BETTA, around half the operating costs were associated with contractual payments to National Grid and Scottish Power for the interconnector. About a third of the remaining cost was for network rates. When these two elements are taken out of the cost base, the performance of SHETL is comparable to the DNOs. This aligns with our expectation (since SHETL and SHEPD are run by the same management team).
- 6.3. We would therefore urge Ofgem to retract this inaccurate comparison as wholly unrepresentative of the efficiency improvements made by SHETL.

Question 7.2: How should non-operational capex be treated with regard to 1) the assessment of efficiency of associated activities such as IT; 2) the treatment of historically incurred overspends; and 3) the approach to future remuneration?

- 6.4. We believe that non-operational capital expenditure should continue to be included in the operating expenditure allowance.

Question 7.3: Do you have any comments on our comparison of unit cost trends? Are there reasons why transmission licensees should have performed differently to DNO's?

- 6.5. As noted above, there is no reason why SHETL in particular should have performed differently to DNOs. Indeed, when analysis is carried out in a more objective manner, we can demonstrate that SHETL has in fact performed in a similar way to the DNOs.
- 6.6. We are disappointed that Ofgem has not shared this inaccurate analysis with SHETL prior to publication and would welcome further discussion on this.

Question 7.4: How should we treat non-controllable costs? Should we take the same approach to network rates as in DPCR?

- 6.7. We continue to believe that non-controllable costs such as rates and licence fees should continue to be pass through items. At the regular ratings reviews we have consistently sought to minimise the overall rates bill and will continue to do so. However, there is a limit to the extent that licensees can influence the rating authorities and rates should therefore be a pass-through item.

7. 7: Financial issues

Question 8.1: Are there other issues that the cost of capital study should address?

Cost of Capital

- 7.1 While CAPM is relatively simple to use and is well understood by UK regulators, we believe that a range of measures should be used to estimate the cost of equity. For example, models such as the dividend growth model or some form of arbitrage pricing model such as Fama-French's 3-factor model can provide a useful cross-check on the results of CAPM. Furthermore, we believe that it is essential that Ofgem continue to use market evidence to supplement these theoretical models in coming to a final decision on the cost of capital.
- 7.2 In our view, in order to continue to attract equity investment, efficient transmission licensees should be capable of earning around 6%, post-tax real, including scope for outperformance. As a consequence, we believe that this points to an allowed cost of capital comparable with the outcome of the recent electricity distribution and water reviews.
- 7.3 We would certainly reject the suggestion made in the consultation that transmission and the use of TIRG model is less risky and hence should be afforded a lower cost of capital. In the case of SHETL, we may be required to make investments of four or more times the existing RAV over the current price control period, which is an unprecedented scale of growth compared to the rest of the sector. Most of this investment is driven by the need to provide infrastructure for new renewable generation, which is inherently uncertain and the scale of investment will raise significant issues in relation to financeability. The need for a TIRG-type mechanism for load-related expenditure underlines the fact that we are moving into a more uncertain, and more risky, investment climate than has been the case hitherto.
- 7.4 We do not therefore believe that it is credible to argue that the current climate for SHETLs' investment profile is less risky than for other companies. A TIRG mechanism would simply set out the circumstance in which a new ex-ante allowance for investment would be made available to licensees. Once set, the project would be subject to the normal RPI-X disciplines and hence similar construction, delivery and other risks as alternative investments. In this regard, the TIRG regulatory regime does not provide any more certainty of cost recovery than "normal" investments that would ordinarily receive an ex-ante allowance in the price control review. It is also apparent that the construction and deliverability risks would be higher for TIRG schemes because of the scale of the projects concerned.

Financial Stability

- 7.5 It is clear that we are moving into a new era in the development of network businesses. Ageing assets, new environmental regulations and the growth in renewable generation are all contributing to increased investment in these

businesses. It is therefore appropriate to review and update the recommendations of the Joint Regulators report.

- 7.6 The need to continue to attract equity investment in transmission and other network businesses is we believe, vital to maintaining incentives for efficient operations going forward. Historically, the existing framework has provided regulatory stability for some fifteen years and this has done much to create a pro-investment climate in the network utilities. In our view, if the cost of capital is set at the appropriate level, network utilities will be able to attract equity and adequately finance their operations. If there are short-term concerns about key financial ratios, these can in most instances be considered cashflow issues and can usually be addressed by such options as tilting depreciation or providing a revenue uplift.
- 7.7 We will be commenting in more detail on these issues, including the proposal for a split cost of capital, in our response to the joint Ofwat/Ofgem consultation on the subject. In brief, however, we are generally concerned that the proposal for a split cost of capital could actually increase perceptions of regulatory risk, rather than, as intended, reduce it.
- 7.8 That said, the profile of SHETL's investment is markedly different from other utilities. In the scenario one forecasts submitted with our BPQ, for example, we illustrated that potential investment could be over £1bn in the next price control period. When put in the context of a current RAV of £300m, this raises obvious financeability issues. In the first instance, this underlines the need for an appropriate cost of capital, but it may, unlike for the sector generally, also point to a need for a different regulatory solution.
- 7.9 In light of the unique issues raised by the need to finance SHETL's investment programme, we would propose that the Terms of Reference in Appendix 17 include a section dealing with 'the magnitude of forecast investment and associated risk' that covers the following:

“Consideration should be given to the large scale of planned investment and its short to medium term impact on the financeability of the licensees' businesses. The forecast capital expenditure is on a scale not previously seen and it will come with significant risks, including those associated with cost and timing as well as design and construction risks. Gearing constraints mean that significant equity injections are likely to be required. Any recommended structure for returns on investment and cost of capital needs to be mindful of these circumstances.”

Question 8.2: How should we approach our assumptions for the cost of debt? Should we use medium term historical averages?

- 7.10 As noted in the consultation paper, recent yields on government bonds are at historical lows, but we believe that this is a short-term issue caused by changes in the pensions regulations and the near-term imperatives of the large pension funds. In our view, the cost of debt financing presently observed in the market is not sustainable over the medium term and longer term. There has also been significant volatility in the debt markets in recent months. For example, in the last two months we have seen volatility in yields on Government bonds with

increases of around 50 basis points for 10 year Gilts. It is also clear that licensees will have a mixed profile of debt, much of which is at rates that are higher than observed in the market currently (but which were nonetheless efficiently incurred at the time).

- 7.11 We note that the recent DPCR adopted an approach of using medium term historical averages of debt costs to smooth out the effects of short-term volatility. However, there is evidence that the use of long-term time series data provides more stable, statistically robust estimates for the risk-free rate. Therefore, we would suggest the cost of capital study should have regard to this as it reviews ‘up-to-date developments in academic research and analysis’.

Question 8.3: How should we reflect the risk profiles of licensees in estimating the cost of capital? Are risks below the market average?

- 7.12 Beta estimates are highly sensitive to changes in market volatility and are highly variable over time. Hence, we do not believe it is appropriate to use recent historical Beta data given the unpredictable and volatile nature of the market in recent years. The use of long-term data will increase the robustness of beta estimates and improve their stability over time. We would therefore suggest that this issue be taken regard of in the cost of capital study.
- 7.13 More generally, we would repeat the point noted above in relation to the investment profile of SHETL. Given the level of equity investment required for TIRG-related projects, we believe that risk will be increased, and not reduced as indicated in the Third Consultation document.
- 7.14 For example, it is apparent that SHETL will be competing with a number of utilities for capital to fund such large-scale infrastructure investment (e.g. railways and water companies also have large current capital programmes). It is therefore apparent that capital providers, including equity, have a large pool of possible investments. As a consequence, it is vital that the allowed cost of capital, however derived, is sufficiently attractive to encourage equity investment in the transmission businesses. In this regard, we do not believe that the assumption of 7.5% in the distribution review for the cost of equity is sufficient, particularly given the scale of SHETL’s investment program relative to RAV.

Question 8.4: Should we still use conservative gearing assumptions and assume target ratings "comfortably within" investment grade when setting the cost of capital and assessing financial stability? What financial indicators should we use?

- 7.15 We consider that the gearing levels and target ratings should remain at levels similar to those used in previous price controls. The ratios used in previous reviews are consistent with a rating comfortably above investment grade, which we consider is important to maintain the financial strength and flexibility of network businesses to undertake the required investment. This is particularly the case in transmission, given the scale of investment and the fact that much uncertainty remains about the exact investment required. It is, for example, conceivable that investment requirements could be higher than

indicated in Ofgem's open letter and hence licensees need to retain financial flexibility to respond to potential future changes. We consider that the ratios used in previous reviews achieve that objective and we would be concerned about the impact for financeability if tighter ratios were adopted.

- 7.16 However, as noted above, the position of SHETL is unique given the scale of the investment required over the next price control period relative to RAV. Accordingly, while the broad ratios used in previous reviews remain relevant, other approaches to financeability may be required in these unique circumstances, including equity injection (which will require a higher return on capital).

Question 8.5: Which option (or combination of options) should be used to address the loss of income from pre-vesting assets becoming fully depreciated?

- 7.17 Provided that the cost of capital is right, financeability issues should in general be minimised and if, as noted above, there are short-term concerns these can be addressed by such options as tilting depreciation or providing revenue uplift.

- 7.18 We believe that tilted depreciation could be applied to electricity transmission in the same way as the distribution price control review. This will go some way towards improving cash flows at a time when increased investment is required. However, as noted above, it is likely that significant equity injection will be required for SHETL and more flexibility over the businesses' financing over this investment phase may be required.

Question 8.6: Do the existing ring-fencing conditions provide adequate protection for consumers?

- 7.19 The transfer of Midlands Electricity from Aquila to Central Networks proved the robustness of the financial ring-fencing arrangements for regulated utilities. Since DPCR4 and the sale of the four GDNs they have been tightened further to include a cash lock-up mechanism.

- 7.20 In our view, therefore, the existing financial ring-fencing arrangements for the electricity sector, including a cash lock-up provision, are sufficient to allow the undertakings of the licensee to be fully separated from other group entities and provide adequate protection to consumers.

Question 8.7: Is benchmarking the level of total employment costs the best means to incentivise the licensees to control their pension costs?

- 7.21 We agree that Ofgem should apply the same broad policy principles to recovery of pension costs as apply in the electricity distribution review. In particular, and in common with the principle applied to the ex-PES pension

schemes, the deficits arising from employees of competitive functions should not be recovered through the price controls of monopoly activities. We also agree that Ofgem should apply the same policies in relation to ERDCs as for the distribution companies (a 70:30 split of liabilities, to reflect the respective share to customers and companies of efficiency savings), even where the schemes were in surplus at the time.

7.22 However, we do agree that NGG should be allowed to recover any funding of the pension scheme over the current price control period in excess of the amounts allowed in the price control. In particular, the circumstances of that business are different, since it was given an explicit allowance for pension costs, unlike in other companies' price reviews. We would not however support the application of over/under funding to past periods where no explicit allowance for pension costs are made, as this would be retrospective in nature and indeed a largely arbitrary calculation given the lack of data. There would therefore be a risk that such a retrospective adjustment could raise issues of regulatory risk.

7.23 We do not understand what Ofgem have in mind by way of benchmarking of total employment costs to ensure efficient levels of pension costs. While generally we consider benchmarking a useful tool we do not believe that it is appropriate in this instance for the following reasons:

- Today's management cannot influence a high proportion of pension costs being paid today. The differing levels of deficit inherited by the Transmission companies mean that benchmarking would not be a fair approach;
- It is not appropriate to judge pension costs together with other employment costs as they have different drivers. They are a result of historic investment performance, age of workforce, number of pensioners etc;
- Benchmarking pension costs would require all the actuarial valuations to use the same assumptions (which would not be appropriate) and for the benefits provided by the schemes to be the same; and
- The small number of transmission companies and the different nature of their activities also makes benchmarking inappropriate in this instance.

7.24 Since pension costs are largely a function of staff numbers (which are incentivised through the RPI-X framework) and the rules of the pension regulators, we see no reason for Ofgem to introduce a specific incentive mechanism for pension costs. Instead, we consider that transmission licensees should be provided with a similar "true-up" mechanism for *efficiently incurred* pension costs relative to the allowance during the 2007-2012 period, as was the case in the recent electricity distribution review.

Question 8.8: Should there be any ex post adjustments to the licensees' revenue allowances for tax payments?

7.25 We agree that Ofgem should attempt to set an ex-ante, company specific allowance for tax as part of the price review. The paper asks whether there should be adjustments made ex post for events out-with company control e.g. material changes to the tax framework. There is clearly a balance to be struck here between appropriate incentives to manage tax affairs efficiently, without exposing licensees to additional risk. We consider that this issue could be addressed by inserting a relevant change of law provision in the licences to address circumstances where there is a material change. Such a mechanism would allow licensees (or indeed Ofgem) to apply for additional (or lower) revenue, but only where it could demonstrate that there had been a significant and unexpected change to tax law. It is likely that such a provision would not have to be relied on mid-price control, but this would nonetheless be a proportionate protection against legal uncertainty.

7.26 The paper also asks whether events that are within company control should be adjusted ex post. However, if such a mechanism were to be developed it is difficult to see how this would be materially different from pass-through of actual tax costs, which would be simpler to implement. Similarly, it is difficult to see how adjusting ex-post for “changes during the price control” would be consistent with the incentive properties of an ex-ante allowance. As a consequence, we believe that Ofgem should adopt either a pass-through of actual tax costs or an ex-ante allowance with a relevant change of law provision, rather than more complex and less transparent “half-way” measures. A third alternative would be a new incentive scheme for tax costs with rewards and penalties for performance against a target of efficient tax costs, subject to a cap and collar. Such sliding scale incentives have been used elsewhere to deliver efficient regulatory outcomes, but would become very complicated in the case of tax costs. We would therefore not support this option.