Transmission Price Control Review - SSE response to 4th Consultation

1. Cost assessment and Policy

Question 6.1: *Do you think our proposed approach to the costs incurred in the current price control period in respect of increasing capacity at St Fergus is appropriate?*

1.1. While we do not know the exact circumstances under which NGG reached a decision to invest in additional capacity in relation to St Fergus, it would appear to have been delivered through National Grid's licence obligations to respond to users' needs for capacity.

1.2. In effect, users signalled their requirements for capacity in the prevailing arrangements and National Grid responded by providing the capacity. Ofgem are now proposing to introduce revenue drivers in electricity to link the need for investment to a user's commitment to utilise the capacity. It does not inspire confidence in the proposed arrangements if expenditure carried out in gas and based, we believe, on similar arrangements is to be disallowed.

Capitalisation

1.3. We agree that it is appropriate to adopt an individual approach to cost allocation and capitalisation since it would be difficult to establish common ground among the licensees given their widely different scale and organisational structure.

Question 7.1*: Do you agree with our proposed treatment of non-operational capex and 'quasi capex'?*

1.4. We agree that non-operational capex should be treated as an operating cost, consistent with the treatment in distribution. We also agree that "quasi capex" (for example repainting transmission towers to extend life) should be classified as capex.

Question 7.2*: Do you agree with our proposed approach to future input price changes and indexation? Is our assumption of a 1.5% annual efficiency saving for opex realistic and appropriate?*

1.5. We are concerned that recent evidence of input price variations could mean that proposed capital expenditure is considerably under estimated. We share Ofgem's concerns regarding alternative indexation models and therefore agree that indexation should remain as RPI. Nevertheless, we firmly believe that all the available evidence of cost increases should be taken into account in determining the ex ante allowances for capital expenditure and in setting the revenue drivers.

1.6. We do not agree with the proposed 1.5% per annum annual efficiency savings, particularly for SHETL. SHETL has a particularly low level of controllable opex in relation to the size of the transmission asset base. It will therefore be particularly difficult to achieve such an efficiency saving from the normalised base expenditure.

1.7. We are also concerned about some of the items excluded in the normalisation exercise, since this seems not to allow some legitimate ongoing charges. For example real wage inflation is to be expected given the incremental progression along salary scales. We are also not clear how Ofgem has calculated the allowances going forward and an audit trail is urgently required so this can be verified.

Treatment of Wind Generation

1.8. In our view, using pre-defined constraint unit costs will lead to a divergence between the planning process for new transmission infrastructure and the TPCR parameter which releases funding for a project. In planning new investments, the licensees must meet their obligations under the GBSQSS, including an economic test of the efficiency of the proposed investment. This efficiency test will be driven by observed or estimated market behaviour and therefore the "real" constraint costs could be different to the pre-defined ones.

1.9. If the observed constraint costs are higher than the TIRG costs, this would mean that licensees might be obliged to carry out an investment to comply with the GBSQSS, yet not have triggered the investment under the TPCR parameters. Conversely if the real constraint costs were lower, the licensees might be rewarded for carrying out an uneconomic investment.

1.10. We therefore believe that, while it would be appropriate to set initial trigger points for investment based on the TIRG costs, these should be kept under review through the investment planning process to ensure that the assumption does not lead to the potential unintended consequences mentioned above.

Question 7.3*: Is our assumption on efficient connection design for wind generation, and the associated reduction to some of the company cost forecasts, appropriate?*

1.11. The introduction of the “plugs” charging methodology has caused a number of issues in transmission system planning. This is because assets charged as connection under the earlier methodology are now classified as infrastructure and therefore subject to different constraints. In particular, the transmission licensees are required to construct infrastructure according to the requirements of the GBSQSS and this in general dictates a firm level of infrastructure. In contrast, generators used to choose a connection design appropriate to their requirements and their required level of security, knowing that they would have to pay for the connection assets directly.

1.12. We agree that the incentives on generators to select the most efficient infrastructure design have disappeared under this methodology. However, Ofgem's consultants appear to have set aside the provisions of the GBSQSS and determined that only if the generator capacity is over 100MW would firm infrastructure be economically efficient.

1.13. On the basis of the consultant's assumption, the amount of the reduction to SHETL's forecast seems appropriate. However, the consultant's assumption implies either a change to the GBSQSS or a change to the charging arrangements to restore the earlier economic signals to the generator. Ofgem has indicated that it has asked National Grid to modify its charging methodology to restore this economic signal. We believe this work should be progressed urgently, since it would clearly be untenable for the transmission licensees to be contractually bound to provide firm infrastructure (because the economic signal for the generator was inadequate) yet the funding to be disallowed as uneconomic.

1.14. We therefore agree with Ofgem's proposed policy, but two adjustments need to be made to the regulatory framework to correctly reflect this policy. Firstly, the non-firm discount needs to be cost-reflective and of sufficient magnitude to encourage generators to make appropriate trade-offs between the cost (to them) and security of their connection.

1.15. Our initial view from the "disallowed" cost in Ofgem's consultant's reports is that the discount from "firm" use of system tariffs should be at least £4/kW to reflect this saving in infrastructure costs. However, National Grid's initial presentation to the Charging Issues Standing Group indicated a discount of only 16p/kW, which would be inadequate

1.16. Second, even if the level of discount is correct, generators may not choose the non-firm option. The revenue driver design will need to take into account the possibility that generators may still choose "firm" connections. Also, if Ofgem's consultants' recommendation is to be followed, the licensees will be obliged to provide firm connections for generators over 100MW. Again, the revenue driver should be capable of dealing with this.

Capex for Operational efficiency

1.17. We agree that capex for specific schemes already identified should be included as an ex ante allowance in the price control. For other schemes that may come to light during the price control, we believe the decision to invest (or not) should remain with the TO following the practice established in the SO-TO code. We believe that remuneration should be through the normal price control mechanism (including retrospective funding).

Cost uncertainty

1.18. Recent upward pressure on prices is a major concern in setting opex and, particularly, capex allowances. We agree with Ofgem that it may not be appropriate to consider at this stage using different price indices in setting allowances. However, the recent movement in these indices should be used as part of the information in setting revised allowances for the price control.

***Question** 7.4: Do you think that we need to allow explicitly for the possibility of reopening the price controls for specified single events where the timing and level of costs is uncertain and driven by third party decisions? If so, what might such events be and why?*

1.19. We agree that, as in electricity distribution, there are particular circumstances under which the price control may need to be reopened. In this case the issue relates to the ongoing provision of rented BT circuits for system protection purposes. Under some scenarios the costs of maintaining the existing facilities may simply increase according to the market pressures. Alternatively it may not be possible to maintain the required level of service and the licensees may need to seek out alternative means to maintain system security. At present it is not clear what may come out of BT's review and we therefore believe that the price control should include specific income adjusting events for BT 21^{st} Century networks.

Capex incentives

***Question** 7.5: What do you think of our proposed options for setting incentives for efficient capital expenditure?*

1.20. As we have stated in our previous responses, we believe that rolling capex incentives already introduced in the Scottish controls should be continued. Ofgem should therefore set out the ongoing incentive payments due from the 2003/4 and 2004/5 rolling incentive mechanism that would apply for the first three years of the new price control. Ofgem should also confirm that rolling incentives will apply for the 2007-2012 period.

1.21. In the conclusions document for the 2005/6 and 2006/7 Scottish transmission price control rollover, Ofgem concluded that a rolling incentive should not be introduced for that period, since a thorough analysis of capital expenditure had not been carried out. However, now that Ofgem's consultants have carried out a thorough review of the proposed expenditure, we believe there is no impediment to introducing a rolling incentive mechanism for that period.

1.22. However, we are firmly opposed to the suggested weakening of the capex rolling incentive to only 20%. This would be inconsistent with the rolling incentives in distribution. In our view it would also be counter-intuitive to water down incentives at a time when the industry is facing a step increase in capex.

1.23. We also believe that an information quality incentive mechanism as described in the March consultation paper should be introduced in transmission. This mechanism would provide for different returns for companies depending on the results of the review of non load-related capex forecasts by Ofgem's consultants and the difference between outturn and forecast plans. We believe that such a mechanism for transmission investment could improve Ofgem's information on efficient costs and provide improved incentives in relation to capex forecasts.

Non Controllable Opex

1.24. Ofgem licence fees are clearly non-controllable costs and local authority rates are fixed for the majority of the price control period. For these reasons, we continue to believe that both licence fees and rates should continue to be subject to cost pass-through, as is the case now and in the electricity distribution price control.

Reporting Requirements

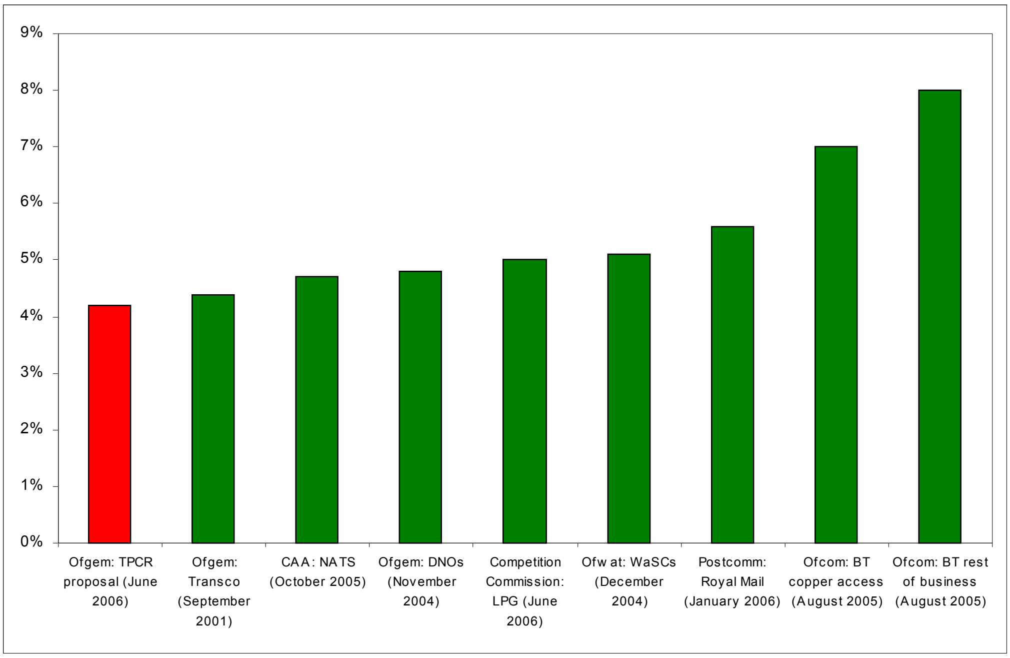
1.25. Ofgem has indicated that it proposes to introduce enhanced regulatory reporting requirements. We accept that this is likely to be necessary given the number of potential new mechanisms to be introduced, including revenue drivers, and various incentive mechanisms. However, it is important to ensure that the reporting requirements are proportionate and also that the timing is consistent with preparation of other financial information. In particular, we believe that the submission of any regulatory reporting pack should be in September, consistent with the accounting timetable.

1.26. We also believe that, as part of the regulatory reporting requirement, Ofgem should confirm each year's regulated asset value, as envisaged for electricity distribution.

2. Cost of Capital

Introduction

2.1. In setting an indicative cost of capital Ofgem has used the CAPM model, consistent with earlier price control reviews. The indicative number that Ofgem has used is lower than any recent comparable reviews, as shown in the table below.



2.2. Although the cost of debt has reduced since finalising the DPCR4 proposals, there has only been a fifteen basis point reduction in the average of five, ten and twenty year maturity gilt yields between November 2004 when the Distribution price control was finalised and June 2006. In our view, this is not sufficient to explain the significant reduction in the cost of capital that has now been proposed.

2.3. We believe that this indicative cost of capital will be insufficient to finance the considerable capital investment required in the transmission sector. It will be particularly inappropriate for SHETL, which has the lowest RAV of the three licensees, but proportionally the largest capital expenditure programme, and consequently a proportionately higher project risk. In this section we comment on the underlying assumptions and set out our views on the cost of capital.

2.4. The four key inputs are the cost of equity, "beta", gearing and the cost of debt. Each is commented on below.

Cost of Equity

2.5. While CAPM is relatively simple to use and is well understood by UK regulators, we continue to believe that a range of measures should be used to estimate the cost of equity. Ofgem has criticised the Fama-French 3-factor model for its lack of statistical reliability and the Dividend Growth Model (DGM) for the implied circularity of logic. However, Ofgem also acknowledge that economic regulators have used DGM as a cross check on rather than a substitute for CAPM. It is also vital that Ofgem has regard to allowed returns in comparable utility and infrastructure markets, against which the transmission licensees must compete for capital. We believe that such cross checks, including DGM are a valuable insight in checking whether a transmission licensee can attract equity finance.

Dividend Growth Model

2.6. The Dividend Growth model has historically been used as a cross check on the inputs to the CAPM model. In SSE's case, commitments have been made to deliver 4% real dividend growth as far as 2008.

2.7. With current share price levels and conservative assumptions for dividend growth beyond 2008, this implies a cost of equity of at least 8%.

PFI Finance

2.8. It is particularly important for this price control given the anticipated increase in investment and the acknowledged need for equity injections to maintain financial ratios. Indeed the SHETL financial profile is a particular issue given the scale of the investments in relation to the RAV. In this context, the risk profile of SHETL going forward will change significantly and also more sharply than the other transmission licensees. The funding requirements for such a business going forward are more akin to a major construction project than the traditional wires business with a steady RAV.

2.9. For this reason, we believe that another useful comparator in setting the equity return for SHETL is the expected returns for PFI finance. A typical current PFI project could earn equity returns in the region of 15% as illustrated by the quotations below:

"we believe that management typically targets IRRs of 14-18% (post tax real), pre any re-financing which would raise the IRR. Some of the projects are achieving more than this: we think the IRR of the London Underground Power System PFI is over 18%."

The second Age of PFI, Collins Stewart, May 2004

…most early PFI contracts were let on the expectation of an IRR to investors of 15 to 17 per cent…

"Update on PFI debt refinancing and the PFI equity market, Balfour Beatty", April 2006 Source: National Audit Office.

2.10. In competing for equity injections it is difficult to see why a company would invest in SHETL when returns for PFI projects are significantly higher than Ofgem's current proposals.

Financeability

2.11. Financeability will be an issue for SHETL in particular. Ofgem's own analysis indicates that an equity injection of £32m would be required to maintain financial ratios. This equity injection has been based only on a capital expenditure of £164m over the five year price control period.

2.12. The equity injection therefore does not include the major outlay for the Beauly-Denny project which, while subject to a separate funding arrangement, still affects the overall financial ratios of the company. Nor does it include any of the other potential investments to facilitate renewable generation. These could amount to a further £650m in SHETL's submitted scenario or up to £1.9bn if all the accepted connection offers proceed.

2.13. Tilting the depreciation profile shows a marginal improvement to cash flows but would not significantly reduce the need for equity injection. Even the baseline capex will require significant equity injections and we believe this points to a requirement for equity returns at the upper end of the range.

Equity Beta

2.14. A company's beta reflects the unique risk associated with owning its shares by comparing movements in its share value with movements in the value of the market as a whole. There is no agreed method for forecasting betas and the lack of consistency between parties attempting to measure a company's beta can lead to unrepresentative betas being quoted.

2.15. Also, the 2003 "Smithers Report" commissioned by the Joint Regulators Price Control Group concluded that the beta of a regulated utility is unlikely to be substantially different from that of the average market beta of unity. There is also substantial regulatory precedent for adopting a beta of 1, for example the electricity distribution price controls.

2.16. Also a review of investors in the water sector in 2005 concluded that electricity transmission was riskier than water. This would mean that it would be inappropriate to use a lower equity beta in transmission than in the water sector.

2.17. We therefore see no reason for moving from the long established practice of using a beta of 1 for the transmission licensees.

Cost of Debt

2.18. In setting the cost of debt, we believe it is important to maintain consistency within and between price controls. For this reason, we do not believe that the current low cost of debt is sustainable in the long term or consistent with earlier assumptions.

2.19. We accept that current risk free real yields are lower than at the last distribution price control review. While we accept that interest rate cycles have become shallower in the past 10 years or so, they have also become longer and we are still very much towards the bottom of the current one. It is reasonable to expect (both in the context of the UK and the wider world economy) that risk-free rates in the UK over the medium / longer term are likely to move / average around a base of circa 5% (being 2.5% real + 2.5% inflation). We therefore believe that the appropriate risk free rate should be 2.5%. This is also consistent with the recent Competition Commission conclusion on 'Domestic Bulk Liquefied Petroleum Gas' Appendix K, June.

2.20. We also believe that a 1.1% debt premium, while close to an average figure for the past 10 years, is too low in the current climate. The lowest that this premium has traded since 1998, however, is circa 0.6% but the high has been 2.25%. Credit is perceived by most market participants to be too cheap at the moment, with a credit "event" probably overdue. Depending on the shape and form of any such event, the balance of probability is that at some point sooner rather than later credit spreads will spike sharply higher before settling down again, probably at a level higher than the historic average.

2.21. Furthermore, the typical debt premium for an "A" rated bond with a ten year maturity would suggest a debt premium of 1.29%. Taking a simple average of ten year spreads for AA to BBB would suggest a debt premium of 1.5%.

2.22. Taking these factors into account, we therefore believe that an appropriate debt premium should be at least 1.25%.

Gearing

2.23. While it may be true that increased levels of gearing may still be consistent with maintaining adequate financial ratios, the large capital programme for SHETL in particular means that gearing up will not be adequate to fund investment and equity injection will be required. Increasing the gearing also has the potential to increase the perceived business risk and hence the marginal cost of debt. We therefore believe that a consistent assumption should be used on the gearing of SSE's network businesses so that both the distribution and transmission businesses are assumed to remain at 57.5%.

Conclusion

2.24. Based on the above analysis, our conclusions on an appropriate cost of capital compared to Ofgem's initial proposals are set out in the table below.

Component	Ofgem View	SHETL View	DPCR4
Risk free rate	2.30%	2.50%	2.75%
Debt premium	1.10%	1.25%	1.35%
Cost of Debt	3.40%	3.75%	4.10%
Equity risk premium	5.20%	5.50%	4.75%
Equity beta	0.9	1	1.0
Cost of Equity	7.0%	8.0%	7.5%
Gearing	60%	57.5%	57.5%
WACC pre tax	6.03%	7.01%	6.91%
WACC post tax	4.22%	4.91%	4.84%

2.25. The theoretical calculation indicates a post tax cost of capital of 4.91%. However, it is clear that the ability to attract equity injections will be driven by real market perceptions and expectations rather than any inputs to an economic model. It is also clear that to fund the substantial capex programme, SHETL will have to compete with other utilities (such as WASCOs) with allowed returns above the CAPM range, as well as other infrastructure providers (such as PFI projects). For these reasons, we believe that a cost of capital in excess of 5%, post tax real, could be justified.

3. Other Financial Issues

Tax Allowances

Question 8.1: *Should the licensees' revenue allowances for tax payments be set to avoid any need for ex post adjustments?*

3.1. Where possible, ex post adjustments should be avoided to ensure that incentives are preserved. The revenue driver should therefore include an allowance for tax as the liabilities are expected to materialise. This is a complex issue and we therefore need to address the revenue driver mechanism urgently.

Regulatory Risk

Question 8.2*: Are there any other measures which could be taken to reduce perceptions of Regulatory risk and what level of risk do these regulated utilities carry relative to other plc's?*

3.2. The key issue regarding regulatory risk is the disparity between the life of transmission assets, a return on which drives the bulk of the income of the licensees, and the five year price control period. The key reason for a five year periodic review is the difficulty of setting a revenue allowance for a longer period that would be robust to changing external influences. While we understand and agree with this reason, it is nevertheless important to ensure that investments carried out in one period continue to be rewarded appropriately in subsequent periods. Any perceived risk of regulatory inconsistency from one review to the next could deter investment.

3.3. In this context, the setting of the cost of capital is important since investors will make decisions on whether to undertake investment based on the expected risk and return profile over the lifetime of the asset. Inconsistent approaches to the costs of capital and over aggressive response to current information rather than long term trends could lead to lifetime returns on some assets being lower than that expected at the time of making the investment.

Pensions

3.4. We currently expect the SHETL pension fund to be in balance or surplus at the time the price review is set. Accordingly, the issues raised in the consultation paper do not apply to SHETL. However, we would agree with Ofgem that in the interests of regulatory certainty the same principles should apply to pensions in the transmission price review as was applied at the last distribution price review. In addition, we believe that Ofgem should make an explicit assumption in relation to pension contributions of the licensees during the 2007-2012 period and commit to a "true-up" mechanism for contributions in excess of (or less than) that assumption.

Revenue Drivers

3.5. The proposals to introduce revenue drivers as discussed in the following sections introduce new uncertainties into the price control framework. To minimise the impact of this, we believe there should be caps and collars to the exposure of the licensees to these mechanisms.

4. Incentive Mechanisms - Electricity

Revenue Drivers

Question 10.1*: Is our proposed two-part revenue driver design appropriate and proportionate to the issue it is seeking to address?*

4.1. We set out in our response to the March consultation our detailed concerns with revenue driver models and we believe these points still stand attached again as appendix 1 for reference. In particular, we believe that a revenue driver mechanism is likely to lead to sub-optimal investment and to promote unintended consequences.

4.2. However, since Ofgem appear to be firmly set on such a mechanism we have set out our further thoughts on how an acceptable revenue driver might be structured. In this context, we believe a two part arrangement is appropriate since the characteristics and risks relating to local infrastructure and deep infrastructure are very different. Our further ideas on the structure of revenue drivers for "local" and "deep" transmission infrastructure are set out below.

Local Infrastructure

4.3. Two options have been proposed for a revenue driver for the local infrastructure. These are the "formula" approach and a "£/MW plus pass through" approach. The formula approach relies on a complex functional form based on a number of project-specific components. While we believe this could result in a reasonably accurate revenue driver, there is a risk that it could be extremely difficult to codify in the licence and to audit in regulatory returns.

4.4. The alternative approach would involve a revenue driver with say 80% of the project cost being passed through with an additioanl term to allow recovery of the remaining 20%. We believe that this will be much easier to set out in a licence condition, and there is precedent for a similar scheme in electricity distribution. We therefore prefer the "pass through plus £/MW" approach. However, there are key characteristic of transmission that, we believe, would make the detailed design different to that for distribution.

4.5. Firstly, we believe that the baseline should contain projects that are already under construction, consented or applied for consent. In SHETL's case this would equate to about 50% of the projects in the submitted scenario, consistent with Ofgem's consultants assessment of the baseline. This would provide a substantial degree of certainty of the baseline, such that a normal ex ante allowance can be included in the price control.

4.6. Secondly, the revenue driver should then increment revenues upwards from this baseline when additional projects progress. This avoids the complexity of a two-way revenue driver and would simplify reporting mechanisms.

4.7. Third, the ex-ante allowance should also include 30% of the project costs of our best forecast of likely generation projects, so that the necessary preconstruction work can be carried out. We believe this would be an appropriate measure to fund the necessary preconstruction works highlighted in paragraph 1.48 of appendix 10.

4.8. We also believe the local infrastructure driver should be subject to a cap for high cost projects such that costs above the cap are passed through.

4.9. Such a mechanism would provide funds for the majority of work, yet provide an incentive for the timely delivery of capacity. Unlike the distribution mechanism, we do not believe there should be a shadow RAV for generation infrastructure (since it would not be subject to separate charging arrangement) Instead, we believe that at the next price control, the efficiently incurred expenditure should be added to the main transmission RAV (with the MW driver continuing in the next price control period).

4.10. It is clear that such a mechanism will be extremely complex and accordingly work needs to commence in developing the detailed framework as a matter of urgency.

Deep Infrastructure

4.11. The options for deep infrastructure are either a "pass through plus £/MW" as for the shallow model, or a "step release" mechanism. Given the size of the potential deep infrastructure projects and the range of £/MW costs, we believe the pass through plus £/MW model would involve considerable risk, and possibly lead to unintended outcomes since there would be a perverse incentive to delay investment until sufficient MW had "signed up".

4.12. We continue to believe that the TIRG mechanism already introduced for major projects is the most appropriate means of dealing with this uncertainty. However, a suitably designed step release mechanism could form the basis of an acceptable scheme going forward.

4.13. We believe the key elements of such a mechanism can be found in the proposals that Ofgem has developed for Gas Exit in Appendix 16. These are:

(a) Named Projects

(b) Estimated Capital Expenditure

(c) Revenue Driver per project (i.e. annual allowed income for each triggered project based on an annuitisation factor as a proxy for depreciation, return and operating costs)

4.14. In addition, trigger points would need to be defined which would release the revenue driver funding for the project. We believe an initial assessment of the trigger could relate to the volume of generation that would cause the system to fail to comply with the GBSQSS. There may be other unforeseen issues that might trigger the funding to be released earlier or later than this ex-ante yardstick.

4.15. Reasons for early release of the funding could include taking the opportunity of outage windows to achieve an overall economic benefit. Later release of funding might occur if constraint costs are lower than anticipated (perhaps due to the introduction of new transmission access products) such that a higher volume can be accommodated. There should therefore be a mechanism for the licensee to seek to vary the timing of project funding.

4.16. A further distinction in electricity compared to gas is that there is a risk that consent conditions could significantly vary the scope of the project from the one that has been "pre-approved" in the mechanism. For example, a requirement to underground part of the circuit could significantly increase the cost. The mechanism would therefore need to allow the licensee to seek variations to the cost in such circumstances.

4.17. It should be recognised that the costings for these potential projects as submitted in the FBPQ are not fully worked up, since they are essentially feasibility studies based on assumed routings. The formal costing would be provided after the detailed preconstuction work at which point it could be embodied in the licence.

4.18. For these reasons, the step release mechanism would only be acceptable if it included a robust mechanism for costs and allowances after the scheme had progressed through the planning phase.

Island Links

4.19. We believe a step release mechanism as described above should also be capable of funding the island links once the design has been finalised and costs firmed up. We do not believe that competition should be introduced in provision of transmission infrastructure for the reasons set out in answer to question 10.2 below.

Question 10.2*: What are the costs and benefits of seeking to facilitate greater competition between providers of transmission services, in respect of the prospective transmission links to the Scottish Islands?*

4.20. We see no reason for Ofgem to consider seeking alternative routes for the competitive provision of infrastructure, since the island links are simply upgrades of existing infrastructure within SHETL's authorised area in the same way as the existing distribution voltage links are part of SHEPD's infrastructure.

4.21. We are concerned that Ofgem is seeking, at this stage in the price control process, to seek greater competition in the provision of infrastructure. SHETL has been progressing for some time with surveys and other necessary preconstruction work which has been underwritten by developers. To introduce a new process at this stage would introduce a further level of uncertainty at a time when SHETL is trying to finalise an economic connection arrangement, so that NGET can produce indicative TNUoS charges and developers can then decide if their projects are economically viable.

4.22. The costs would therefore include the following:

- Recurring costs in duplication of effort in route finding, surveying etc.
- One-off costs of establishing changes to the licensing framework to allow additional transmission owners and accession to the SO TO Code.
- Cost of Ofgem developing its own technical expertise to be able to assess the alternative project designs and costs before awarding a licence.
- Lack of co-ordinated transmission planning.
- Additional interfaces

4.23. The benefits are unclear since the existing licensee is obliged to determine the most economical way to connect generators, and is obliged to tender for the work under national and European procurement legislation.

4.24. Ofgem could also leave itself open to challenge as "micro managing" the transmission network in approving technical designs.

Access Review Options Development Group (ARODG)

4.25. Ofgem and National Grid have consulted separately on revision to the transmission access arrangements. While this review is being carried out separately from the transmission price control review, it is clear that there is a strong linkage with the proposed "user commitment" which might be used to release funds under a revenue driver arrangement. Also, as mentioned in 4.15 above, the introduction of new access products might vary the point at which transmission investment becomes necessary.

4.26. There is therefore a risk that delinking the ARODG work from the TPCR will result in a mismatch between the funding derived through the revenue driver arrangements and the actual funding requirements of the licensee. The timetable for the access review and the wider transmission price control review need to be better aligned by Ofgem. If this is not possible, the licence conditions following the transmission review, particularly in relation to revenue drivers, should be capable of being reopened following fundamental changes to the access arrangements.

Question 10.3*: Is our proposed approach to funding for innovation appropriate and necessary?*

4.27. We continue to believe that an innovation funding initiative is appropriate and agree with Ofgem's proposals to introduce an Innovation Funding Incentive.

Questions 10.4*: Is our proposal to extend the existing performance incentive scheme appropriate?*

4.28. We are opposed to a "penalties only" scheme for transmission interruptions. A penalties only arrangement can not be considered an incentive, since there would be no incentive to outperform the minimum standard. In addition the design parameters of much of the SHETL 132kV network are such that interruptions will occur with a first circuit outage. This is a significant difference to the situation on the heavily meshed "supergrid" of 275 and 400kV circuits.

4.29. If Ofgem were to introduce a penalties only scheme, we believe that there should be an ex ante allowance to ensure that the base level of performance can be delivered within reasonable expectations.

5. Gas Incentives

Question 11.1*: What do you think of our revised proposals for setting entry capacity release obligation baselines, and for the proposed mechanisms for enable such baselines to be re-allocated in some circumstances?*

5.1. We have set out in previous responses our fundamental concerns about the existing gas entry regime. In our view, the existing regime has distorted competition, unnecessarily increased perceptions of regulatory risk of 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 believe that the revised proposals do not address these fundamental concerns, although we do recognise that some attempt has been made in the latest document to address particular issues.

5.2. For example, we welcome Ofgem's decision to retain the concept of baseline capacity release obligations defined for each entry point rather than the alternative approach that was consulted upon in Ofgem's third TPCR consultation paper. In our view, the alternative approach proposed gave disproportionate discretion to NGG NTS and added considerable opacity to the capacity release mechanism.

5.3. Clearly, the setting of accurate baselines is critical to the proposed capacity release and the associated incentive mechanisms. We support an approach that sets nodal baselines in accordance with the practical maximum capacity of the system. However, it will be necessary to ensure that these baseline levels truly reflect the physical capability to ensure that NGG NTS is not rewarded for capacity that is already there. We note that indicative baselines for both entry and offtake capacity have been provided and we will provide specific comments on these separately.

5.4. In order to alleviate Ofgem's concerns that a nodal baseline approach could lead to capacity becoming "sterilised", Ofgem has proposed a mechanism that could reallocate capacity between nodes. We agree that substitution of spare capacity from one location to another is consistent with the efficient and economic development of the NTS. Accordingly, we would expect NGG NTS to optimise the use of capacity across the network in the normal course of events. However, we do not believe that where this takes place, there should be a corresponding change to the associated baselines. We continue to believe that this would inappropriately transfer risk from NGG to Users of the system and adds further complexity through the introduction of exchange rates etc.

5.5. Notwithstanding the above, we note that Ofgem continues to support a substitution framework for both entry and offtake capacity that results in baseline changes. To that end we believe that substitution should take place after the long term allocations of capacity and it should be subject to a robust and transparent methodology that is approved by Ofgem. Furthermore, any baseline substitution should be approved by Ofgem and participants at each location consulted upon and given the opportunity to revise their capacity requests prior to any substitution being agreed. It is not clear from Ofgem's proposals whether capacity would be permanently substituted or whether substitution only takes effect for the period for which the capacity has been committed at the receiving location, transferring back to the original node after that period. Certainly, we firmly believe that NGG NTS should not receive incremental/incentive revenue for capacity that has been substituted from one location to another.

5.6. We also note that Appendix 11 describes a further substitution mechanism that would be associated with the medium/short term allocation of entry capacity. Ofgem explains that under this approach, a User would inform NGG NTS that they wish to bid for unsold capacity at entry point A for transfer to entry point B. NGG NTS would charge the User for the modelling required to calculate an exchange rate. The User would then compete for capacity at location A and, if successful, would be obliged to transfer that capacity to location B according to the agreed exchange rate. In essence therefore, entry capacity in the constrained auction would be sold on a global/zonal basis.

5.7. While we recognise that allocating unsold baseline from location A to location B is efficient where this can be achieved, we are concerned that the proposed approach adds further risk and uncertainty to the Users of capacity at each location. Certainly, if Ofgem's approach were to be progressed we believe it would be far more open and transparent if, at the very least, exchange rates were published to the industry prior to any auction taking place. We do not believe that it would be appropriate for NGG NTS to charge Users separately for the calculation of exchange rates since this could result in multiple payments for the same work.

5.8. Given the interaction between entry and offtake capacity and that the delivery of incremental capacity at entry can lead to increased offtake capacity, or vice versa, we support the proposal that would require NGG NTS to increase baseline levels to reflect these interactions where appropriate.

Question 11.2: *Are our proposals for revenue drivers for entry and offtake appropriate and proportionate, given the issues they are seeking to address?*

5.9. Ofgem's initial proposals continue to support the application of revenue drivers that would adjust revenue allowances consistent with the efficient provision of new capacity in response to demand. We note that the principle is applied equally to the delivery of both new entry and exit capacity, although the mechanisms for each are slightly different. For entry, Ofgem has calculated revenue drivers for different capacity bands for each entry point. For offtake, Ofgem has proposed a zonal revenue driver for incremental capacity below a certain threshold, plus project specific drivers in relation to those large projects which are currently anticipated, with further revenue drivers being determined on an ad hoc basis as and when required. In both instances, Ofgem proposes that the revenue driver would apply from the point at which the additional capacity is contractually delivered for a period of 5 years, after which the actual, efficiently incurred costs would be included in the RAV.

5.10. While we have hitherto opposed the application of revenue drivers, we believe that, if there are to be such revenue drivers, the mechanisms described in Appendix 11 for entry and Appendix 16 for enduring offtake (and summarised above) go some way to addressing our concerns. We therefore believe that in the main, the proposals for revenue drivers are appropriate given the uncertainty associated with future incremental capacity requirements (although we continue to believe that simpler mechanisms could deal with such uncertainties). Nevertheless, one area that remains unresolved is the application of a revenue driver for offtake flexibility capacity. We have discussed this in more detail under our response to the questions raised in Appendix 16.

Question 11.3: *Are our proposals for buy back for entry and offtake appropriate and proportionate, given the issues they are seeking to address?*

5.11. Ofgem's initial proposals for capacity buyback associated with the non/late delivery of new entry/exit capacity is based upon an administered buyback price if NGG NTS does not deliver capacity by the contractually agreed date. The agreed date is either a default investment lead time or one that has either been agreed bilaterally with the User or alternatively altered with the approval of Ofgem. Any exposure, or reward where NGG NTS has negotiated an alternative bilateral agreement for delivery, would be treated as excluded revenue.

5.12. We agree that under a user commitment model NGG NTS should be exposed to any costs of late delivery. We also believe that the exposure should be related to the market price while recognising that unlimited liability is not a realistic option. We therefore see merit in Ofgem's proposals for entry that prescribes a market based administered buyback cap related to the average OCM price for 2005/06. However, we believe that the buyback cap should be entry point specific (rather than applying equally to all entry points) and should track the prevailing OCM price (rather than being set as a uniform price to apply through the period of the next price control review). We believe that this approach would achieve a better balance between the issues associated with unlimited liability exposure for NGG NTS and a User commitment model.

5.13. Notwithstanding the above, we believe that further consideration must be given to the implications for a DN where NGG NTS is unable to deliver offtake capacity by NGG NTS within the contractually agreed timescale. In these scenarios, there are likely to be limited alternative investment decisions/options available to meet the DN's requirements at "short notice". Therefore, it is likely that the DN would be exposed to additional expense in seeking to mitigate the failure by NGG NTS to deliver that capacity, for example, exposure to increased interruption costs on their own networks.

5.14. We believe that for operational buybacks of entry capacity, Ofgem's proposals to essentially continue the existing regime at entry is appropriate. That is, a target-based incentive with sharing factors, caps and collars the specifics of which are yet to be determined. It would also seem appropriate that NGG NTS should face a greater exposure than it currently does given that incremental buybacks have been removed from this incentive and baselines are to be based upon practical maximum physical capacity levels, rather than theoretical capacity levels.

5.15. We also agree that it would be appropriate to continue the prevailing arrangements to manage operational offtake buybacks. That is, the continued use of a prescribed number of maintenance days, which if exceeded are subject to administered compensation arrangements prescribed in the UNC.

Questions 11.4: *Is there a case for an innovation incentive for NGG NTS?*

5.16. We believe that Ofgem should introduce innovations funding incentive arrangements in gas transmission, along similar lines as in the electricity 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 different treatment between gas and electricity transmission in this regard.

<u>Appendix 16 – Offtake revenue drivers and baselines for NGG NTS</u>

5.17. Ofgem has set out more detailed discussion on the proposed way forward for NTS offtake arrangements in the context of both the transition and the enduring regime in Appendix 16. We have commented on these more detailed proposals below.

The Transitional Regime

Question A16.1 *Do you agree with our Initial proposals for the transition period in respect to: a) Baseline levels; b) Revenue drivers; and c) NGG NTS incentives?*

Baseline levels

5.18. Ofgem has identified that its initial proposals for baselines in the transition period are consistent with the proposals that were set out in the Third TPCR consultation. That is, in the absence of a full user commitment model, the baseline levels would be used to delineate between the funding of the existing NTS asset base and the remuneration of incremental investment only. Baselines would not be associated with an obligation to offer capacity for sale during that period. This would seem appropriate. We will provide comments separately on the proposed baseline levels.

5.19. Ofgem has also stated that it does not intend to set baselines for interruptible capacity. We understand that this is because the purpose of the baseline is to trigger incremental allowed revenue for NGG where additional investment has been made on the system. Since no investment is made to deliver interruptible capacity this approach would seem appropriate.

5.20. We also agree that it would be appropriate for the baselines for the transitional period to be set at the same level (i.e. practical maximum physical capacity) and on nodal basis as under the enduring regime. We also agree that no baselines should be set for flexibility capacity in the transitional period since no investment is anticipated by NGG NTS for incremental flexibility during this period. We also note that there is considerable uncertainty surrounding the definition of this product and, in particular its relationship to flat offtake capacity. As a consequence, to set a baseline at this stage would, we believe, be impracticable.

Revenue drivers

5.21. We agree that if revenue drivers are to be adopted for the enduring regime, Ofgem's initial proposal to apply the same revenue drivers to the transitional period as those that would be applied to the enduring regime and that their application would be contingent upon delivery of capacity seems appropriate. Likewise, since the transitional ARCA arrangement does not represent a full user commitment model for non-specific, load related reinforcement Ofgem's proposals to require NGG NTS to submit to the Authority for approval an annual report detailing those investments that do not have a specific user commitment and the rational for such investments also seems appropriate.

NGG NTS Transitional incentives

5.22. We support Ofgem's initial proposals for the incentives that would apply to NGG NTS for the transitional period. That is, we agree that the charges foregone and exit investment incentive be removed for the reasons Ofgem has described. We also agree that the constrained LNG incentive should be retained but with sharper targets applied and where possible licence drafting simplified. Finally, we agree that the greater than 15-day interruption incentive should continue for the transitional period but there should be no buyback related costs allowed.

The Enduring Regime

5.23. We continue to believe that an extensive user commitment model has a number of significant issues associated with it. These concerns were described in our response to the Third TPCR consultation and we have not, therefore, repeated them here except to repeat the point that, in our view, a User's commitment should be limited to requests for *incremental* NTS offtake capacity above baseline. We therefore continue to support the principle behind the prevailing rights model proposed by NGG's strawman, however, we believe that the commitment periods for existing and new capacity (two and a half years and four years respectively) are unduly onerous.

5.24. Ofgem has restated the view that revenue drivers should be contingent upon an appropriate user commitment and therefore, revenue drivers should apply to all load related capex in the next price control period. Furthermore, Ofgem believes that if NGG NTS invests purely to meet investor's user commitments, it will be deemed to have met its 1 in 20 obligation. As we indicated in our last response, we believe that this approach effectively absolves NGG entirely of its investment responsibilities other than reacting to other parties' information provision. We therefore believe that as owner and operator of the NTS, NGG should take more responsibility for ensuring compliance with its investment obligations than suggested by Ofgem's dependence on the user commitment model.

5.25. We are extremely concerned that to date issues associated with offtake product definitions remain outstanding. In particular after significant weeks of debate and industry participation, NGG NTS has withdrawn its proposals for an "expanding flexibility" product. We regard this as unacceptable and, if these reforms are to be implemented, the definition of the flexibility product needs to be addressed as a matter of urgency.

***Question A16.2**: Do you agree with our initial proposals for baselines in the enduring period including the adjustments proposed?*

5.26. We agree that it would seem appropriate to use a practical maximum physical approach to determine the level of nodal baselines.

5.27. We note that Ofgem believes that the enduring period baselines should be consistent with those set for the transitional period. However, Ofgem believes that there should be upward adjustments (from zero) to the baselines of the five interruptible sites in the constrained south west quadrant since capacity at these sites has historically been made available without the need for investment. We support this approach since we understand that otherwise NGG NTS could be inappropriately rewarded for the provision of capacity that is, in effect, already there.

5.28. However, we firmly believe that Ofgem should also consider the application of this approach to storage sites where historically, NTS offtake capacity has always been available even though it is registered as interruptible capacity. Indeed, we note that there remains an outstanding action to consider the interactions of entry and exit capacity at storage sites with a view to setting appropriate offtake baselines.

5.29. While we appreciate that the discussion to date on baselines has been focussed on the obligation to sell capacity and the trigger for the application of the revenue driver, it is essential that clarity is provided as soon as possible on the prevailing rights that will apply to Users at each node.

Question A16.3*: Do you agree with our initial proposals regarding the introduction of a substitution obligation on NGG NTS?*

5.30. Please see our response to Q11.1 above.

5.31. In addition, we welcome Ofgem's view that where substitution has taken place, NGG NTS would only receive additional remuneration for additional capacity provided once substitution opportunities had been explored by implication. We therefore understand that revenue drivers would not be applied to capacity that had been substituted to one location from another. Furthermore, we welcome Ofgem's clarity that Users who had a prevailing right to capacity could not have such capacity "substituted" away to another node as long as they continued to make the rolling financial commitment.

Question A16.4*: Do you agree with the indicative revenue drivers proposed?*

5.32. As we have indicated above and in previous responses, we have a number of concerns with the application of revenue drivers going forward. Nevertheless, as we have set out in our response to Q11.2 above, we believe that Ofgem's proposed approach goes some way to addressing our concerns in this respect.

Question A16.5*: Do you agree that our proposals for addressing entry/exit interactions are appropriate?*

5.33. As we have mentioned in our response to Q11.1 we support the proposal that would require NGG NTS to increase baseline levels to reflect the interactions between NTS entry and exit capacity where appropriate. However, we are unsure how this would be achieved in practice.

Question A16.6*: Do you agree with our proposals with respect to buybacks of offtake capacity?*

5.34. Please see our response to Q11.3 above.

Question A16.7*: Do you agree with our initial proposals for financial incentives on NGG NTS with respect of release of non-obligated and interruptible capacity?*

5.35. We agree that in principle, NGG NTS should be incentivised to release non-obligated and interruptible capacity. The obligation to release baseline capacity should continue up to and including the gas day. As such, non-obligated capacity would be capacity released above baseline for which a sustained signal had not been received.

6. Environmental Considerations

***Question 12.1**: Do you agree with our assessment of the main impacts of the transmission system? What are the most important impacts from the perspective of consumers?*

6.1. We agree that Ofgem have identified the key environmental considerations associated with transmission systems.

6.2. As far as emissions are concerned, we note that Ofgem has mistakenly reported oil leakage from SSE's distribution, rather than transmission business which is considerably less (400 litres rather than 40,000 as reported). In this context we have plans to replace some of the poorly performing cables which will reduce oil losses. We have also scheduled to replace a number of transformers, which will also reduce the risk of oil leakage. However, we note that Ofgem, in these proposals, has suggested that the number of transformers to be replaced should be reduced. Our replacement proposals are based, we believe, on a robust risk assessment including the possibility of failure and hence potential oil contamination. We therefore believe that Ofgem's proposals run counter to the environmental considerations and the transformer replacements should be allowed.

6.3. We comment on SF6 emissions in the answer to Q12.2 below.

6.4. We agree that possible increase in transmission losses are a consequence of a wider commercial context in that renewable generators tend to be situated in remote locations. It would not be possible, therefore, to introduce a losses incentive in transmission since it is a second order consideration in the wider framework of renewable energy and reduction of carbon emissions.

6.5. We also agree that the case for additional allowances for undergrounding transmission lines on the grounds of visual amenity is less compelling than in distribution. However, where the permission to construct a new circuit is conditional on part of the route being underground, we believe the funding allowances should reflect this constraint.

***Question 12.2**: Should emissions of SF6 be subject to a separate incentive scheme, given that they are currently outside the scope of the European Emission Trading Scheme (EU-ETS)*

6.6. SF6 is currently the only available alternative to oil as an insulating medium at transmission voltages. Consequently the volume of SF6 gas in use on the transmission system is likely to increase rather than decrease over time as ageing switchgear is replaced and as the system grows to accommodate new renewable generation. We would therefore be opposed to any incentive arrangement to reduce SF6 emissions overall.

6.7. It may be possible to design an incentive to minimise the <u>percentage</u> loss of SF6, similar to the losses incentive in electricity distribution. We would not be opposed to such a scheme, but is not clear what the overall benefits would be, since operationally there is little that can be done to reduce SF6.

Question12.3*: Should there be additional measures to promote innovation in support of environmental benefits, either as part of the proposed incentive scheme for innovation for NGET, SPT and SHET or as a separate measure?*

6.8. We believe the innovations incentive arrangements should be capable of covering innovations in support of environmental benefits, and so there should not be a separate scheme for this.