Transmission Price Control Review: Updated Proposals

Response from Scottish and Southern Energy

1. Price Control Policy & Cost Assessment

Operating cost allowances

1.1. In general, we welcome the progress that has been made since the initial proposals in addressing the licensees' concerns regarding the cost assessment process and the overall policy framework. However, we believe there remains some way to go to determine an efficient level of baseline costs. In particular, we are concerned that the input cost increases that have been observed in recent contracts have not been properly reflected in the baseline capex allowance. We believe the baseline capex allowance should fully reflect this increase as discussed in 1.14 below.

1.2. Also we do not agree with the phasing of the opex allowance associated with the increased asset base. Whilst the total incremental allowance over the review period appears reasonable we would expect the opex costs to be increasing as the assets become established. This means that the profile of the incremental allowance should match the growth in the asset base rather than the capital expenditure profile. We also believe that the ongoing efficiency assumption of 1.5% is inconsistent with what is achievable given the relatively small baseline operating cost of Scottish Hydro Electric Transmission Limited ("SHETL"). In addition we note that Ofgem has allowed a certain level of real wage growth, but this is inconsistent with the actuarial assumptions used in our March 2006 pension actuarial valuation and with our actual experience of real wage growth.

1.3. We therefore believe that a 1% per annum cost reduction together with reprofiling the opex allowance to match the cumulative growth in the network and real wage growth consistent with the actuarial assumptions should be incorporated in the proposals.

Rates pass-through

1.4. Also, we believe that rates should be treated as pass-through for the entire period, not just until the rates review in 2010. In our view, the licensees should be assumed to be efficient and effective in their approach to the review and their input to the review assessed ex post in setting revenue allowances for the post 2012 period.

Post Vesting Connections

1.5. We agree that post vesting connections should continue to be treated as an excluded service, noting that post vesting, but pre-BETTA connections for the Scottish licensees were incorporated into the revenue allowance as part of the transition to BETTA.

However, this means that post BETTA connections in the case of the Scottish licensees should be treated as an excluded service.

Regulatory Reporting

1.6. Regulatory reporting is highlighted as a requirement for the transmission licensees going forward. In this regard we would urge Ofgem to develop reporting arrangements that are proportionate to the size of business given the large differences between the licensees and also to consider the timing of the annual submission of the reporting to ensure that workload on Distribution & Transmission regulatory reporting can be efficiently accommodated.

Question 7.1: Do you agree with our proposed incentives for efficient capital expenditure, including a 25 per cent incentive rate?

1.7. In general, we believe that such dilution of incentives compared to existing regimes could undermine incentives to operate efficiently. It is also not clear at present from the information in the consultation paper exactly how such a mechanism would work. We are particularly concerned that such a mechanism would not address the periodicity problem that the rolling incentive mechanism addresses. We continue to believe that a capex rolling incentive mechanism for non load related expenditure as introduced for the 2002/3 to 2004/5 period would be more appropriate. However, we are aware of more general concerns regarding the continued application of an undiluted incentive in the face of the very large capital investment programmes anticipated.

1.8. Given these concerns, we would therefore propose a variation such that the rolling incentive would only apply for capex within plus or minus 10% of the forecast level. This addresses the periodicity problem and caps the rolling incentive exposure to an acceptable level. Outside this range, the 25% retention as proposed by Ofgem would apply to underspends between 80-90% of the allowance. For underspends greater than 80% of the allowance, Ofgem's reopener mechanism would apply, subject to the caveats mentioned above.

Question 7.2: What do you think about our proposals to address significant capex under spend? In particular:

(1) What action should we take if this happens?

(2) At what level should we trigger this response?

(3) Should this response apply to load related and non load related capex?

1.9. We understand the logic for developing proposals to address significant capex underspends, but we believe that any such proposals should be symmetrical to deal with circumstances where the licensee overspends the capex allowance, subject to the usual efficiency tests.

1.10. Also, we believe that the "sliding scale" incentive mechanism introduced for electricity distribution would be a better way to incentivise licensees to submit reasonable forecasts for non load-related capex requirements, rather than to potentially reopen the price control in the case of significant underspend.

1.11. However, if Ofgem are to proceed with this potential reopener mechanism, we believe that the initial action should be to request reasons for the variation in capex from the forecast levels. This would enable variations due to year on year fluctuations to be addressed. For example a delay in a major project might cause one year to be below the threshold, but subsequent years to be above the threshold. Action should only be taken if the average underspend (or overspend) over the period exceeds 20%. The action taken should involve an adjustment to the allowed revenue commensurate to the degree of under or overspend.

1.12. The proposals should only apply to non load related capex since this is more under the control of the licensee. Load related capex is driven by the requirements of customers and is consequently much more uncertain. It should not, therefore, be subject to this constraint. In any case, there are different proposals to deal with the uncertainty regarding load-related capex, i.e. the revenue driver mechanism.

1.13. In summary, our proposals as described in the answers to questions 7.1 and 7.2 above involve the following:

- A 5 year rolling incentive mechanism to be applied for capital expenditure in the range of 90-100% of forecast expenditure
- A 25% retention as proposed by Ofgem for capital expenditure in the range of 80-90% of forecast expenditure
- A resetting of the price control for cumulative expenditure below 80% of forecast expenditure during the period (and not just focussing on individual years)
- Reciprocal arrangements for overspend – i.e. rolling incentive for the 100-110% range, 25% retention in the 110-120% range, and resetting for cumulative expenditure over 120%

Question 7.3: Do you agree with our proposed approach for dealing with uncertain costs including future input price changes, specific cost uncertainties, and wider regulatory developments?

1.14. We agree that input cost variations should be dealt with through ex-ante allowance because the alternatives (such as use of new input cost indices) could introduce even greater uncertainty or unintended consequences. In this regard we have made submissions to Ofgem as to how the input cost variations seen in recently awarded contracts would affect our proposed capital programme. The allowance made by Ofgem in the September proposals falls somewhat short of this, and we would urge Ofgem to make a further adjustment in the final proposals to recognise the full amount required to make up this shortfall.

1.15. We agree that any costs incurred as a result of the introduction of BT 21st Century Networks should be capable of reopening the price control if these costs are significant. If the costs incurred are not large enough to justify reopening the price control, we agree that the costs should be captured through a logging up procedure. However, Ofgem should make clear that logging up qualifies for retrospective funding including financing costs (i.e. so-called “pot 3” funding). This mechanism should also be formalised in the licence modifications.

Question 7.4: What do you think regarding the proposed regulatory treatment of NGG's use of affiliated LNG?

1.16. Ofgem is seeking views on the proposed regulatory treatment of NGG's use of affiliated LNG facilities. In particular, how funding of the LNG facilities should be provided going forward given its current role in providing Operating Margins and System Support to NGG NTS. On the grounds that Ofgem believes NGG NTS can procure these services from other sources, Ofgem has decided that it is not appropriate to fund the investment through the main TPCR. The above debate, therefore, is now focussed on how to set the regulated prices that NGG NTS is permitted to pay for the services in the event that a competitive market for the services does not materialise.

1.17. It would appear that the above debate has focussed only on the use of the facilities by NGG NTS. That is, to date, no mention has been made of the application of the regulated price to the use of the Glenmavis LNG facility by Scotia Gas Networks (SGN) to meet its obligations relating to the independent systems associated with that network. Therefore, any increase/removal of the regulated prices will have an immediate impact on SGN and its own price control review for 07/08 and beyond. While we believe it is desirable to reduce regulation where there is effective competition, it is clearly not appropriate where the service in question is in effect a monopoly. In our view, the Glenmavis LNG facility is a monopoly service provider for the LNG requirements associated with SGN's independent system obligations. We therefore believe that this factor should be taken into consideration when considering the regulatory treatment of these facilities going forward. If price controls are nonetheless removed from the Glenmavis LNG facility, it will be necessary to include a full cost pass through for this service in SGN's price control.

2. Financial Issues

Cost of Capital

2.1. Before addressing specific Ofgem questions and commenting on the particulars of the "Smithers" report, we have expanded upon the key considerations in determining the cost of capital that Ofgem has identified:

- consistency with past regulatory decisions;
- the investment focus of the review;
- financeability assessments;
- the overall balance of risk the companies will face; and
- consultants' work.

We agree that these are key considerations and have commented on each in turn.

Consistency with past regulatory decisions

2.2. We believe that this is one of the most important factors, for two reasons. Firstly regulatory consistency and stability is vitally important for investor confidence

particularly given the investment requirements in the forthcoming period. Secondly, SSE has always had the same rate of return in its transmission business as in its distribution business and we believe there are very good reasons for this.

2.3. We have argued that the cost of capital should be at least equal to distribution and believe that should still be the case. In every price control Ofgem has set, transmission and distribution in SSE have always had the same cost of capital. The 4.2% cost of capital in Ofgem's Initial Proposals for Transmission is significantly lower than the existing 4.8% used in Distribution.

2.4. We believe that there are very good reasons for maintaining the relationship between the transmission and the distribution cost of capital. In SSE the transmission and distribution businesses are run in an integrated fashion and the optimum overall design for system development is taken irrespective of the design voltage. At the margin, different cost of capital between transmission and distribution could lead to sub optimal designs based on the voltage providing the more favourable return. Also, 132kV assets are treated as distribution in our E&W distribution business, but as transmission in Scotland. It would therefore be inconsistent to have similar assets attracting different rates of return in different parts of GB.

2.5. In practice, the transmission and distribution system have also been historically very similar in terms of risk and capital expenditure requirements in proportion to the RAV. We therefore believe that the SHETL cost of capital should equal that of SHEPD.

Investment focus

2.6. Unlike previous transmission price controls, SHETL in particular is facing a step change in its investment programme driven by the requirements of renewable generators connecting to the system. This will mean that the RAV of SHETL will at least double in the next period, and could increase many more times depending on the extent of renewable generation being consented.

2.7. The following table illustrates the range of financing requirements of SHETL.

Scenario	Capex Requirement
Baseline Only	£160m
Baseline + Beauly – Denny	£410m
Scenario 1	£1000m
Scenario 2	£1340m

2.8. The baseline scenario includes the capital expenditure identified by Ofgem's consultants for both load-related and non load-related expenditure of some £160m over five years. This is nearly three times the prevailing historic level of capex. The nature of the projects included in the baseline means they are typically of one year construction. This means that the assets go onto the RAV the year after the capex spend.

2.9. In addition to the baseline capex, Ofgem has approved funding for the construction of a new line from Beauly to Denny under the TIRG mechanism. This project alone will

nearly double the RAV of SHETL once completed (this project is forecast to cost £250m) and will take approximately three years to construct.

2.10. Scenario 1 as submitted in our business plan includes a further potential £600m of capex for major transmission reinforcements. If these projects are included, the total capex over the five year period increases to over £1bn.

2.11. A further scenario was submitted with even higher levels of generation connecting (but still only around half the level of accepted offers) which would take the capex requirement to over £1.3bn.

2.12. It is therefore clear that the investment focus of this review means that the overall cost of capital has to be adequate to attract investment.

Financeability assessments

2.13. At simply baseline levels of investment (and excluding the Beauly-Denny project) the financial ratios are within a range consistent with maintaining an investment grade credit rating as required by the licence. At investment levels above this baseline, additional cash injection is required to maintain these ratios. If this is not to be funded by customers through an allowance for additional regulated revenue, it needs to come through an equity injection. As a consequence the cost of capital has to be adequate to attract new equity from the market at market rates. It is a particular issue for SHETL given the percentage growth rate compared to the other licensees. This introduces a differential risk, which may merit a financeability adjustment.

Overall Balance of risk

2.14. An important factor in setting the cost of capital is the perceived overall balance of risk. In this review, the additional large investments in local and main transmission infrastructure are to be funded through a revenue driver mechanism. This represents a new risk to transmission licensees and is a particular issue for SHETL given the scale of the investments compared to the RAV.

Consultants' work

2.15. A number of consultants have provided input into the academic studies of cost of capital, producing a wide range of results. The key elements in the cost of capital using the CAPM method are the various rates (risk free rate, debt premium and the equity returns) with gearing and beta assumptions. In the Smithers report, a beta of 0.5 has been suggested, which is completely at odds with historic precedence in setting price controls.

2.16. The report contains a lot of theoretical discussion on estimating beta and concludes that the rolling regression method of estimating beta understates the degree of uncertainty in beta while the Kalman Filter approach overestimates the degree of uncertainty of beta. There is also an inconclusive discussion around whether UK or World markets should be used.

2.17. Finally the report reviews whether "value" and "size" effects should be taken into account as there is some evidence to support them and therefore using a straightforward beta approach to Cost of Capital may result in underestimating returns. The "size" effect is discounted as being less relevant, both statistically and for the companies in question. The report goes on to conclude that the "value" effect is more statistically supported but Smithers and Co believe that there is no consensus in academic circles as to exactly what it is and how large an impact it should have on returns.

2.18. These academic discussions in the report are not at all conclusive on an appropriate estimate of beta. Indeed, the only conclusions appear to be that beta is very difficult to estimate accurately (the range for the companies quoted in the report is from 0.1 to 1) and that there may be other factors (not yet properly assessed) that would have to be taken into account to reach an appropriate return.

2.19. However, we believe there are two pieces of data from this section of the report that should be considered by Ofgem in setting the level of beta:

- the fact that there would "seem to be fairly clear evidence that the downward trend in betas has halted in recent years and may at least partly have gone into reverse."
- the graphs which chart the trend of beta over time show that it has either remained flat or increased since December 2004 when Ofgem set the cost of capital for DPCR4 with beta at 1.

2.20. We firmly believe that the appropriate level of beta for Ofgem to use is 1.0; this is consistent with the DPCR4 and is not inconsistent with the debate and range of outcomes in the Smithers report. It is also in line with the equity beta of 1.0 suggested by NERA in their "Review of Ofgem's Initial Proposals for TPCR" report for EDF Energy.

Question 8.1: Do you agree with the conclusions of the Smithers & Co cost of capital study, in particular the real cost of debt and equity?

2.21. The Smithers report concludes that corporate bonds are "commoditised". Credit rating and maturity being the factors that will determine the required return. The only thing required to set the appropriate cost of debt is therefore to choose a benchmark, and therefore A-rated bonds have been chosen.

2.22. Long term data on spreads shows that Aaa US bonds long term average is around 80 basis points. (85 since 1993, 101 since 2000). Also UK A-rated bond is 105 basis points since 1993. (105 since 2000)

2.23. Although there is no conclusion on spread in this section the Table in section 1 summarises the required spread over risk free rate for A-rated bonds is 1% - 1.5%. This together with the term premium means that the overall cost of debt range is 3.5% to 4.75%. We would agree that this range is reasonable and would expect the cost of debt to be at least 3.75% given the term premia risks pointed out by Smithers and Co.

2.24. In respect of equity, we would regard 7.5% as a minimum level of equity returns, rather than the upper end as implied by Smithers & Co. Indeed, given the financing issues of SHETL in particular, we would argue that the equity return should be 8% or more.

Cost of Capital - Conclusions

2.25. In looking at the particular components of the CAPM calculation and applying the principles determined by Ofgem, we believe an appropriate cost of capital would be 4.8 - 4.9%. This has been estimated as follows.

Risk free rate

2.26. 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 Smithers report.

Debt premium

2.27. We continue to believe that 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 & 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.

2.28. We therefore believe that an appropriate debt premium is 1.25%, giving a cost of debt of 3.75%, well within the range estimated in the Smithers report.

Equity Premium

2.29. 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 2010. With current share price levels and conservative assumptions for dividend growth beyond 2010, this implies a cost of equity of at least 8%.

2.30. Other comparators were also quoted in our submission to the last consultation including the equity returns available on PFI projects and estimates using the Fama French model. For all the above reasons, we continue to believe that an equity premium of 8% is appropriate.

Beta

2.31. In addition to our comments on the Smithers report in 2.16 to 2.20 above, we would like to make the following points. 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.

2.32. A recent review by OXERA concluded that the beta of a regulated utility is unlikely to be substantially different from that of the average market beta of unity.

2.33. We therefore see no reason for moving from the long established practice of using a beta of 1 for the transmission licensees. It also worth noting that betas have increased since DPCR4 providing a further reason not to reduce beta.

Gearing

2.34. 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 SHETL's network businesses so that both the distribution and transmission businesses are assumed to remain at 57.5%.

2.35. The combination of the above factors have been incorporated into the WACC calculation using the traditional CAPM model in the table below and compared with the Ofgem estimate and DPCR4 for reference:

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	1.0	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%

Question 8.2: Do you agree with our proposed revised treatment of pensions costs?

2.36. We agree that pensions should be treated in a consistent fashion and that the principles developed through the DPCR4 process should therefore be applied. 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.

Question 8.3: Do you agree with our proposed approach to the provision of new equity?

2.37. As Ofgem recognises, equity issuance has a cost associated with it. Indeed the Smithers report acknowledges that equity issuance costs can add between 30 and 80 basis points to the cost of equity. However, we do not believe it is sufficient to promise to allow additional income depending on the outcome during the period.

2.38. Instead, we believe that the key issue is to ensure that businesses can attract equity investment by setting an appropriate WACC. Companies will then finance their activities in the most efficient way. Alternatively a financeability adjustment could be made for companies with poor financial ratios to the same end.

3. Adjustment Mechanisms and Incentives - Electricity

3.1. In general, we believe a great deal of progress has been made in designing a revenue driver mechanism capable of dealing with volume uncertainty in load related capex. A number of key points need to be resolved before the mechanism would be acceptable. There are two areas of work: the mechanism for local infrastructure, and; the revenue driver for deeper infrastructure.

Local infrastructure

3.2. The local revenue driver would come into effect once the volume of generation allowed in the baseline ex-ante allowance has been reached. However, we believe that the £/kW basis quoted in the document for calculating the allowance is too low for two specific reasons. Firstly, the projects in the baseline (on which the revenue driver for non-baseline projects is based) only have about half their costs in infrastructure. This is because they were designed according to the pre-BETTA connection methodology, which contained a large connection charge contribution. The revenue driver for non baseline projects would therefore need to be around twice the estimated figure to cater for the different charging arrangements.

3.3. The second reason is that the baseline projects have selected the most advantageous locations in terms of grid connection. Non baseline projects will, by definition, be connected in more remote locations. On average they are around 50% more expensive to connect. This implies a revenue driver based on around £75/kW rather than the £25/kW assumed in the consultation.

3.4. It should also be noted that this level of revenue driver would only cater for "non-firm" infrastructure, as this is the basis on which costs have been estimated. NGET has brought forward proposals to encourage "customer choice" of non-firm infrastructure by offering a discount to the use of system charge. However, there may be instances where generators continue to opt for firm infrastructure, which would involve, to a first

approximation, a duplication of circuits. This means that a "firm" revenue driver of around £150/kW would be required for such connections.

Deep infrastructure

3.5. For the “deep” revenue driver, the step release mechanism proposed by Ofgem has much to recommend it. However, we should point out that the initial estimates of cost for potential major investments have been based on desktop studies rather than in depth field assessments of routes and environment.

3.6. We therefore welcome Ofgem’s proposal for a mechanism for SHETL to submit a further submission of costs in certain circumstances which might result in the revenue driver allowance being revised. We would therefore urge Ofgem to clarify these circumstances and the arrangements so that the licensees can be clear under what conditions a cost revision would be considered. In our view, the circumstances meriting a review of the projects costs would be where the scope of the project has changed from the original submission due to: environmental considerations; planning and consenting requirements, or; the volume of committed generation. It is also possible that the trigger point could vary dependent on the value of constrained off generation, or the introduction of new access products from NGET.

Licence issues

3.7. While progress has been made on the overall framework for the revenue driver mechanism, a number of issues about the detail remain to be resolved. These will have to be codified in the licence and our experience of the process of drafting the distributed generation incentive implies that Ofgem's attention needs to urgently address the detail policy issues and the licence drafting. This detailed work includes:

- the initial list of projects for the deep revenue driver
- "trigger" points, and means to review if new evidence becomes available
- measurement and reporting requirements
- auditing
- the means to bring forward further projects not foreseen under current generation connection scenarios
- the mechanism to calculate the annual revenue allowance

Question 9.1: Do you agree with our proposal that it is appropriate for NGET to have a different form of revenue driver from SPTL and SHETL?

3.8. We have been engaged with Ofgem for some time on the design of an appropriate revenue driver for SHETL. We now believe that the basic framework for the revenue driver as proposed for SHETL is appropriate to the type of projects under consideration. We have some more detailed observations on the design as set out below. However, the NGET transmission system is considerably different to that of SHETL, both in terms of scale and the effect that the geographical location of generation can have on power flow and the need for investment. In the SHETL area, all additional generation will, in the short to medium term require additional investment

in main infrastructure and the more local infrastructure required to connect. A particular difference is the absence of any 132kV network in NGET's system due to the differing definition of transmission in Scotland compared to England and Wales. For all of the above reasons it is clear that a revenue driver suited for the SHETL system may not be suitable for NGET's and it is therefore appropriate for it to take a different form.

Question 9.2: Do you agree with our proposed mechanism to deal with baseline and revenue driver sample risk?

3.9. We agree that there should be an adjustment once the prescribed MW value has been connected, should the capital expenditure incurred be outside the +/- 15% "dead band".

Question 9.3: Do you agree with our proposed split of revenue recovery between pre-connection and completion?

3.10. In our discussions with Ofgem on the form of revenue driver, a basis for discussion has been the recently introduced distributed generation incentive on the Distribution Network Operators (DNOs). In that mechanism, 80% of the costs are passed through and 20% are subject to the £/MW revenue driver. We believe that this represents a more appropriate balance of risk than the 75/25% proposed in the paper.

Question 9.4: What are your views on the appropriate method of providing connections to the Scottish Islands?

3.11. In answering this question it is important to recognise the fundamentals of the existing licensing regime as it applies to the islands of Scotland. Firstly, the islands fall within the authorised area of SHETL and Scottish Hydro Electric Distribution Limited ("SHEPD"). These companies have existing obligations to respond to demand for capacity in the islands and this has resulted in the situation today when all of the main island groups with the exception of Shetland enjoy connections to the mainland. Shetland does, however, have an extensive distribution network, which is the responsibility of SHEPD.

3.12. SHETL already has the obligation to reinforce the links to the islands and is actively pursuing the options as required by its licence. Indeed SHETL, recognising that rigorous application of the current GBSQSS can result in over-provision of network, is actively pursuing innovative, non-SQSS compliant designs that better meet the generators' requirements. NGET's charging methodology means that generators wishing to connect to the transmission system are obliged to underwrite the necessary work through the "Final Sums Liability" (FSL) arrangements. The same arrangements apply to new generators in the islands. Should these connections be opened up to competition, SHETL would be obliged to recover its costs from the developers via NGET (unless Ofgem determined that the costs could be recovered in some other way)

3.13. It should also be noted that the proposed links are not simply radial lines connecting a new generating station to the mainland grid; the links would perform the dual purpose of supporting demand on the islands. When the wind is not blowing, the power would flow from the mainland to the island, rather than vice versa. It is clear therefore that

the design of the links has to be done as part of the development of the interconnected GB transmission system, rather than a simple radial generator connection (which generators could carry out for themselves if they wished).

3.14. Against this background, it is clear that our preferred option is the status quo, where the TO with the existing licence obligation brings forward proposals in the usual way consistent with the coordinated, economical development of the GB transmission system.

3.15. The alternative that Ofgem appear to be proposing is to open up any point to point transmission link to competition. This could be done in one of two ways, either as "competitive regulated transmission" as is being developed for offshore generators, or on a merchant basis. The implications of each option are discussed below.

Competitive Regulated Transmission

3.16. Clearly, if other transmission licensees were to be permitted to develop transmission systems in the SHETL area, SHETL would want reciprocal rights in other areas. This would mean fundamental changes to the licensing regime that was introduced only 18 months ago with BETTA, meaning a removal of the geographical restriction on providing transmission services to NGET. Such a regime could possibly require even more intervention from Ofgem in assessing tenders for the best solution. Alternatively NGET as system operator could assess the options in its role of making connection offers. However, this would preclude NGET from making a bid, as it would be difficult to demonstrate equitable consideration of bids. The alternative of at least legal separation of NGET SO from the NGET TO business to ensure non-discrimination is unlikely to be acceptable to NGET.

3.17. The option of "competitive regulated transmission" would therefore require the following:

- Removal of the current geographical restriction in licences for providing transmission services
- Removal of the obligation to make connection offers
- Further separation of NGET SO from NGET TO (assuming NGET TO wanted to participate in any out of area activity)
- Obligation on NGET to make any opportunities for transmission reinforcements know to all transmission licensees

Merchant approach

3.18. An even more radical approach would be to allow merchant interconnectors so that the generators could provide their own links. This would raise a number of issues regarding third party access, transmission charging arrangements and the provision of services to the DNO to support local demand.

3.19. In addition to the variations discussed above, the merchant approach would require

- Exemption from third party access obligations

- Modifications to transmission charging arrangements
- Clarification of trading arrangements as to how generators would participate in the market
- Obligation on merchant operator to provide transmission services to island DNOs

Question 9.5: What additional output measures do you think Ofgem should capture when considering system performance?

3.20. It is difficult to determine additional relevant output measures for transmission system performance because transmission is designed to more secure standards than distribution. Loss of supply is an exceptional occurrence typically caused by unplanned outages coinciding with planned outages of parts of the system, or of multiple outages in exceptional weather events. Also in Scotland and particularly the SHETL area it can be the result of 132kV system faults, since large parts of the 132kV system are designed to lower levels of security.

3.21. A further complication is the relationship between NGET as system operator with responsibility for the performance of the system as a whole, and the TO who is responsible for the performance of the plant making up the system. It may be possible to categorise plant unavailability in terms of the primary and secondary causes of the unavailability and hence devise a more meaningful measure of the performance of the TO in providing and maintaining plant that is fit for purpose. In the meantime, we would accept a "penalties only" arrangement for loss of supply incidents provided that there was an ex-ante allowance to deliver the baseline performance and provided there were appropriate exceptions to ensure that exceptional events were excluded from the measure.

Question 9.6: Do you agree with our view that an Innovation Funding Incentive is appropriate?

3.22. Yes, we agree that the IFI proposals are appropriate, and would urge Ofgem to set "de-minimis" allowance for small TOs such as SHETL to ensure that there is a meaningful level of funding available. We believe that £1m would be an appropriate de minimis limit.

4. Adjustment Mechanisms and Incentives - Gas

4.1. Before responding to the particular questions raised by Ofgem in the consultation, we have two general concerns regarding the enduring arrangements for offtake reform and user commitment.

Enduring arrangements

4.2. We note that NGG NTS has raised Uniform Network Code (UNC) modification proposal 0116 (mod 0116) in order to implement the enduring offtake reform that reflects Ofgem's views expressed through the TPCR process. We will respond to this and any alternative modifications that may be raised as part of the usual UNC

modification process. Nevertheless, we believe that there are still a number of key issues associated with the proposed enduring arrangements that must be addressed. In particular an incentive scheme that may be applied to the DNs. We also believe that there are issues associated with the definition of the flexibility product; the level of commitment to be provided by a User requesting capacity (we comment further on this below); and proposed changes to the NTS charging methodology and the impact they will have on DN allowed revenue and associated charges.

User Commitment

4.3. For gas offtake, Ofgem has reiterated that the enduring arrangements should be based upon a user commitment model. There has been considerable debate about the level of commitment that should be associated with a capacity booking, particularly for new, incremental capacity and to date we believe that the proposals brought forward by NGG NTS are too onerous and could, we believe, introduce unforeseen consequences to the gas industry given different Users' ability to provide such commitment. In our view, a User's commitment should be limited to requests for incremental NTS offtake capacity above baseline. Furthermore, Ofgem has stated that if NGG NTS invests purely to meet Users' commitments, it will be deemed to have met its 1 in 20 obligation. We continue to believe that this approach effectively absolves NGG NTS entirely of its investment responsibilities other than reacting to other parties' information provision. We therefore believe that, as owner and operator of the NTS, NTS NGG should take more responsibility for investment than that suggested by Ofgem's user commitment model.

4.4. We understand that a number of concerns have already been expressed in relation to the user commitment required under the interim/transition arrangements. In the event that Ofgem is required to determine on any specific commitment under these arrangements, the outcome could, we believe, have a bearing on the enduring arrangements and may therefore have to be taken into consideration.

4.5. Separately, we understand that the issue of long term contracts for capacity is currently being considered by DG Comp in the context of the wider European energy market. It is therefore essential to ensure that arrangements being considered for the GB market are cognisant of this.

Question 10.1: Do you agree with our proposals for the treatment of entry and offtake capacity release obligations, and capacity substitution?

4.6. The two key issues in the treatment of entry and offtake capacity release obligations are the baseline and substitution and we comment on each aspect below.

Baselines

4.7. Ofgem has very recently published updated proposals for gas entry baselines and compares them with those that were proposed in its June paper and those proposed by NGG NTS. We welcome Ofgem's approach that has updated the proposed baselines to include the sum of obligated entry capacity currently associated with a particular entry

point, to do otherwise would clearly be inappropriate. However, Ofgem's baseline proposal for Hatfield Moor would appear to be significantly higher than that proposed by NGG NTS. We question why Ofgem has assigned the "spare" capacity to this entry point since there is no evidence from the entry auction regime that it will be required at that location but is far more likely to be utilised at other entry points within that zone. While we understand that the substitution proposals could mean that capacity could be moved between entry points at a later date, we believe that this initial allocation of capacity should be allocated to those entry points where the industry has indicated that entry capacity will be required.

4.8. We are also extremely concerned that at certain locations Ofgem has proposed an increase in baseline capacity that could undermine a shipper's decision to participate in the September 2006 QSEC auctions. For example, a shipper will have made a decision based on the existing baselines and UCAGs when deciding whether to request permanent obligated incremental entry capacity and committed to pay the requisite sum of money to secure it. However, Ofgem's proposed increase in baselines at certain locations means that the capacity is, in fact, already there and therefore, the User's commitment to pay NGG NTS for it being "incremental" only one month earlier is wholly inappropriate. This highlights a further risk of the user commitment model in that Users can in good faith give appropriate signals only to find that the price control subsequently undermines that decision.

4.9. We are unsure how Ofgem's proposals to continue to withhold a proportion of baseline entry capacity from the long term auction for allocation in the short term would be compatible with Ofgem's proposals for capacity substitution. We would welcome more clarity on this point.

4.10. For offtake, Ofgem's update document reflects NGG NTS's most recent proposals for the release of separate Offtake flat and flexibility (flex) products and Ofgem's proposed baselines reflect this position which seems appropriate. The baseline proposals for flat capacity are based upon those set out in the initial proposals document with some minor adjustments. We will respond separately to these revised baselines should they continue to cause us concern. The baseline proposal for flex capacity is based upon a single volume of 22mcm across the whole of the NTS. We continue to be concerned about the methodology used to derive this baseline figure and in particular the transparency of the model used.

Substitution

4.11. Ofgem has proposed that future arrangements for both entry and exit capacity should facilitate the transfer of capacity between individual nodes to ensure the economic and efficient use of the network. While we support this principle, we continue to believe that NGG NTS should do this as a matter of course. We are concerned that Ofgem's proposals for the substitution of unsold baseline capacity introduce further complexity and uncertainty to the regime; significantly impact shippers' booking of capacity to date and therefore increase the risk of unforeseen consequences.

4.12. Notwithstanding the wider concerns above, if Ofgem's proposals for substitution are to be progressed, we agree that a substitution obligation would be appropriate and any

interactions between entry and offtake should be reflected in revised baselines. However, assuming Ofgem's views described in paragraph 10.19 apply to entry and exit capacity, we believe that NGG NTS should be required to offer capacity transfer exchange rates to all relevant Users, i.e. DNs as well as shippers where exit capacity is concerned. We certainly agree that Ofgem's approval should be required before any substitution or revision of the baseline is made.

4.13. Turning now to substitution proposals for the short-term entry regime. We believe that where a shipper requests a transfer exchange rate, this should be made publicly available to the wider community prior to the auction process so that Users are entering the auction process with an appropriate knowledge of the environment within which they are participating. Indeed, to not do so would, in our view, potentially fail to meet all but the first of the four objectives set out in paragraph 10.24. Finally, we believe NGG NTS should not charge for the calculation of a transfer facilitation exchange rate since, in our view they should be calculating exchange potentials as a matter of course, however, we would agree that if a charge is to be made, Ofgem's sharing proposals seem appropriate.

Question 10.2: Do you agree with our proposed approach in relation to revenue drivers?

4.14. Ofgem has proposed that as a result of de-linking the charging regime from revenue drivers at entry, it is considering the introduction of a user commitment based on a shipper's willingness to pay transmission charges over a set number of years rather than the current NPV test. We have no objection to relating the user commitment to use of system charges. However, we continue to disagree with the exit proposals that are based upon a commitment to pay *unknown* transportation charges and therefore we do not support this approach being adopted at entry. A User should be fully aware of the sum of the commitment it is entering into to enable it to assess its willingness to embark upon such an agreement. We therefore believe that it is essential that the user commitment is expressed in terms of a fixed sum of money (based on a calculation of the booked capacity times the current use of system charge prevailing at the time the booking is made) paid over a known period of time that is determined at the time the User makes the commitment. This would then be consistent with the approach being developed in electricity. We therefore urge Ofgem and NGG NTS to reconsider their approach in this respect for both entry and exit arrangements.

4.15. We agree that no revenue driver should be set for delivering incremental flex capacity.

Question 10.3: What are your views of our proposals on buy back incentives, in particular, in relation to investment lead times and caps on exposure?

4.16. We have significant concerns over Ofgem's proposals to introduce a "permit" scheme to allow NGG NTS to extend the default investment lead-time for the delivery of incremental capacity. Indeed, we believe that the proposal is a further example of the implications of introducing a hugely complex commercial arrangement for the allocation of capacity. That is, the more complex the arrangements the greater the number of "fixes" that are required to mitigate the unforeseen consequences.

4.17. In our view, Ofgem's "permit" proposal does nothing to protect the interest of Users and their requirement to have certainty as to when they can expect incremental capacity to be made available. Even though Ofgem believes the "permit" would be exercised prior to a long-term auction, the User can have no certainty when planning its own investment as to when or where NGG NTS may decide to use one. This is a particular issue for DN Users that already have significant capacity issues to consider for themselves and which will be compounded by the interaction of DN interruption reform and the new NTS exit arrangements and associated incentives. We believe offering NGT NTS further discretion as to when it delivers incremental capacity is unacceptable. We also see no justification for NGG NTS being allowed to gain additional "permits" to delay future projects just because it delivered a previous project ahead of schedule and believe that it may introduce perverse behaviour if this were allowed to take place. Finally, it would appear that the proposed permit parameter of 30GWh/day is totally arbitrary.

4.18. Turning now to NGG NTS's exposure to buybacks for failing to deliver incremental capacity on time. We assume that DNs as well as shippers would be able to sell back incremental capacity rights to NGG NTS if it fails to deliver incremental exit capacity on time - Ofgem's third bullet under paragraph 10.33 suggests only shippers would be able to do this.

4.19. Furthermore, we are not entirely clear how Ofgem will determine a cap on the price at which Users can sell back incremental capacity. Ofgem suggests at entry it would be based upon on the day SAP and the buyback price for each prompt buyback action taken since 1st April 2002. We believe that consideration should be given to the use of SMP rather than SAP. Furthermore, the majority, if not all of those prompt buybacks taken at entry would have been for operational purposes rather than for failing to deliver incremental capacity. We do not believe that Users would necessary attach the same intrinsic value to capacity that has not been delivered in time with that which has been curtailed for operational purposes. We therefore believe that Ofgem's proposals should be given further consideration particularly since, in our view, a cap of around £0.52p/kWh would not reflect the potential consequential losses associated with that capacity, although we recognise that it would be unrealistic for NGG NTS to bear the full consequential loss of a User. We are also unsure how Ofgem would intend to determine the buyback cap associated with late delivery of exit capacity since no exit buybacks have been made to date. Certainly, a DN should be held neutral to any exposure to cost associated with the late delivery of capacity by NGG NTS.

4.20. Ofgem is also considering an absolute cap of £36m for NGG NTS's exposure under the incremental investment buyback arrangements. We assume this is £36m EACH for entry and exit buybacks. We also assume that this is in addition to any buyback exposure associated with operational capacity buybacks. We suggest that buyback costs associated with late delivery of any project where NGG NTS has "played" one of its "permits" should be excluded from the £36m absolute cap at both entry and exit.

Question 10.4: Is it appropriate to propose an incentive on NGG NTS to release additional incremental flexibility over and above the flexibility baseline?

4.21. We believe that it is appropriate to incentivise NGG NTS to release non-obligated flexibility capacity over and above the baseline. However, we have no working experience of the actual amount of flexibility capacity that is likely to be physically available under the new proposals. We also have concerns over the transparency of the methodology used to derive the 22mcm baseline. We therefore believe that the initial cap for flexibility should be set for one year only to avoid NGG NTS gaining inappropriate rewards in the first year of operation of the new product.

Question 10.5: Do you agree with our view that an Innovation Funding Incentive is appropriate?

4.22. Yes, we do agree with the introduction of an IFI from 1st April 2007 and believe that it is appropriate to consider the lessons learned from electricity distribution in this respect.

Question 10.6: What are your views on our proposals for transitional offtake incentives?

4.23. We agree with the proposals for the transitional offtake incentives as set out in the initial proposals document. However, we are unable to comment on Ofgem's update in respect of the targets proposed for the CLNG incentive without having access to the detailed modelling

5. Sustainable Development and the Environment

Question 11.1: Do you agree that the licensees should be incentivised to reduce leakage of SF6? Do you agree the incentive should be set for 5 years?

5.1. We agree that proposals should be developed to incentivised reduced leakage of SF6. Since the volume of SF6 in use is likely to increase, we believe that the incentive should be in % terms rather than absolute volume of SF6. However, the level of reward should be commensurate with incentivising investment in more effectively sealed plant.

Question 11.2: Do you agree with our proposal not to apply the DPCR approach to transmission undergrounding? Do you have views upon how we may best factor this in to our decisions?

5.2. We agree that it would not be appropriate to apply the DPCR proposal to transmission undergrounding. The relative costs of undergrounding compared to overhead lines for new network in rural areas is much more favourable at distribution voltages, attracting a premium of 30-50%. However, the difference at transmission voltages is typically 6-10 times the cost depending on the terrain.