Transmission Price Control- SSE Response to Second Consultation

1. Framework, Context and Objectives

1.1. We agree with the conclusion that the broad RPI-X framework remains appropriate. We also agree with the conclusion that the flexibility of the price control to deal with external events will be a key consideration for the review. In addition, we would agree that, as a general principle, reopening price controls should be avoided, as far as possible, for the reasons set out in the paper. However, this needs to be balanced against the prospect of other adverse or unintended consequences of alternative arrangements for dealing with uncertainty.

1.2. As a consequence, while we support Ofgem's view that the broad RPI-X framework should be retained and amended to address, in particular, uncertainty of network investment, we do not believe that this conclusion should necessarily mean that, for example, automatic revenue drivers should be imposed for network investment. Similarly, we do not believe that Ofgem should preclude from the outset narrowly defined price control re-openers in specific circumstances, clearly set out in advance, where these can be proven to be a more efficient mechanism for addressing uncertainty than the alternatives.

1.3. We expand on these issues below in more detail in response to the section of the paper on cost assessment and incentives.

2. Cost Assessment

Methodology for Assessing Capital Expenditure

2.1. We have no issues with Ofgem adopting a "top-down" assessment of transmission capex plans, including an assessment of the underlying methods licensees have adopted in formulating forecast investment. We also look forward to supporting Ofgem's work on the BSI-PAS 55 certification.

A Sliding Scale Incentive Scheme

2.2. However, we also see merit in Ofgem considering a "sliding scale" type incentive for non-load related transmission capex, similar to the new capex incentive that was introduced as part of the distribution price control review. Broadly speaking, that framework provides for different returns for companies depending on the results of the review of capex forecasts by Ofgem's consultants and the difference between outturn and forecast plans. We believe that a similar mechanism for transmission investment could have strong incentive properties in relation to capex forecasts as part of the review.

Five Year Retention of Efficiency Savings

2.3. In addition, in setting the two-year extension for the Scottish companies, a rolling incentive was applied to the capital expenditure from 2003 onwards. We believe this mechanism is an important part of the price control package as it removes perverse incentives regarding the timing of efficiency improvements.

2.4. We therefore believe that Ofgem should make clear that the "capex roller" incentive will be applied to capex for the next price control period. This would solve the periodicity problem of efficiency savings and would complement the sliding scale incentive we have described above.

2.5. In applying the capex roller, Ofgem will need to take into account two aspects of the incentive. First, it will need to make it clear that capex savings during the 2007-2012 period will be kept by the company for a minimum of five years and the 2012 price control will provide for recovery of those benefits. Second, in relation to efficiencies made between 2003 and 2007, an adjustment should be made to allowed revenue to recover those savings in the 2007-2012 period. In the case of SHETL some of this revenue was allowed in regard of efficiency savings prior to the two-year extension to 2007. However, the capex roller incentive revenue in that period did not remunerate all of the five-year retention of savings made before 2005 and this will also need to be addressed in calculating allowed revenue from 2007. It will also need to reflect five-year retention of any savings in 2005/06.

Investment to Connect New Generation

2.6. We note the reservations expressed by Ofgem in this section of the consultation paper about the TIRG term. We continue to believe that the TIRG mechanism remains appropriate for remunerating investment to connect new renewable generation. The mechanism is simple, transparent and retains the usual incentive properties of RPI-X regulation. By contrast, alternative approaches involving "automatic" adjustments to allowed revenue via, for example, revenue drivers and/or auctions of capacity tend to be overly complex (leading to unintended consequences), difficult to set in advance and can produce inappropriate incentives (e.g. to delay investment). For these reasons, we would urge Ofgem not to rule out from the outset expanding the TIRG term into the new price control. We expand on this in more detail in section 5 below.

GSBQSS

2.7. In general, price controls should be reopened only in exceptional circumstances. Careful design of the price control parameters and mechanisms for automatically adjusting revenues driven by defined events (such as the "TIRG" mechanism for adjusting revenues when construction on major projects commence) should minimise the likelihood of income adjusting events.

2.8. By its nature, an income adjusting event is something that is unforeseen or unquantifiable at the time of setting the price control and is therefore not capable of being addressed through the price control design. We therefore believe that the transmission price control should contain an explicit mechanism for dealing with uncertain costs, such as the mechanism introduced in the recent distribution price control review.

2.9. Despite the best intentions in setting the price control, there may be unanticipated developments that significantly affect the licensees' costs. In these cases we believe that there should be the capability to request price control reopening and that a refusal to grant a reopener should be capable of being referred to the competition commission.

2.10. In this context, we do not believe it is reasonably possible at this stage to estimate the likely effects of any changes to the GBSQSS in setting ex-ante allowances for the price control. We therefore believe that any GBSQSS costs should be dealt with through a mechanism for dealing with uncertainty.

Impact of "Plugs" on Investment

2.11. We agree that there are a number of peculiarities of NGET's charging methodology that produce unintended consequences for the price control review. This illustrates the risk of overly complex regulatory mechanisms and also highlights the difficulties in setting revenue drivers or similar "automatic" adjustments to determine allowed revenue. We would however agree with the conclusion that there needs to be a thorough review of NGET's transmission charging methodology and this should also address the shortcomings Ofgem identified in approving NGET's tariffs for BETTA go-live.

Network Flexibility

2.12. Ofgem have also queried how allowances might be assessed for flexibility in capacity. This is in the context of changing patterns of usage. However, we believe there will be little change in the pattern of usage (i.e. the location and level of consumption of gas or electricity) but there is likely to be a change in the supply side; new patterns of generation in electricity and changing gas flows as the UK moves to a net import position. As noted above, we believe that a development of the TIRG term would be the optimum means of addressing this uncertainty.

System Operation

2.13. As regards efficient system operation, currently NGET has an incentive to invest in capacity provided the cost leads to a reduction in constraint costs. NGET's SO incentive scheme allows them to retain 50% of the reduction in constraint costs. In Scotland, the TOs are obliged to invest in the transmission system to ensure continued compliance with the GBSQSS.

2.14. While the TOs do not directly benefit though the SO incentive scheme they clearly will retain an obligation to carry out any investment that is economically efficient. Since the materiality of this is generally small in the context of the price control it should be capable of being incorporated into the overall capex programme of the TO by re-prioritising the capital profile. This issue does not therefore justify a revision of the split of responsibilities between the SO and TO in this price review.

NGET SO Incentive

2.15. We believe the SO incentive has been working well and has reduced overall balancing costs. The detail design of the scheme and the scheme parameters are a matter for NGET and Ofgem. Since these parameters will have a significant effect on the costs of providing balancing services, the forecasts should naturally be subject to rigorous scrutiny.

2.16. However, the split of responsibilities between TO and SO has been established though the BETTA process and embodied within the licences and the contractual framework. We firmly believe that there should not be any changes to the responsibilities of the TO and SO in this price control review.

Operating Costs - Methodology

2.17. We recognise that comparisons of operating costs are not as straightforward in transmission compared to electricity distribution. Nevertheless such comparisons and benchmarking may inform the wider review. In this regard, any such comparison should seek to reward efficient performance as well as to penalise poor relative performance. Ofgem's recent approach to the electricity distribution price control effectively achieved this by basing cost allowances on the efficiency quartile, rather than the frontier.

2.18. This helped to strengthen incentives for frontier performance and we would commend a similar approach to Ofgem at this price review, recognising the limitations in comparing the transmission licensees.

2.19. In tandem with the five-year capex roller, we believe that there is equal merit in a five-year opex roller to solve the periodicity problem for efficiency savings of these costs. This is particularly important for the two-year rollover period, otherwise the savings for this period will only be retained for one or two years, undermining forward-looking incentives. This could be achieved by adjusting allowed revenue from 2007 to take into account the value of five-year retention of efficiencies over the current price control period.

Cost pass through & excluded services

2.20. Certain costs such as rates and licence fees have hitherto been treated as a pass through cost and we believe this should continue, as the costs are not within the control of the licensee.

2.21. Other costs such as connection charges and relocation of assets have been treated as an excluded service and we believe that this should continue.

Operating cost allowances for 2007

2.22. In setting operating cost allowances for 2007-2012, Ofgem will need to recognise that the scope for future efficiency savings is limited, given the mature nature of these businesses. Indeed, the transmission licensees face significant upward pressure on costs from, for example: greatly increased volume of connection offers and the increased complexity of contractual arrangements under BETTA; increased repair and maintenance costs associated with the significantly large network by the end of the period; other costs increases associated with operating a larger network such as insurance, procurement, finance and legal, and; increased cost of rented telecommunication circuits. It is clearly vital that future allowed revenues also fully recognise these costs.

Regulatory Reporting Pack

2.23. The document also discusses proposals for enhancing regulatory reporting by the licensees, work on which is expected to begin this summer. We support this process. However, we also support Ofgem's view that any transmission regulatory reporting pack would need to be proportionate. We believe that this would apply to SHETL, which is only around a twentieth the size of NGET and a quarter the size of a typical DNO.

Environmental considerations

2.24. We agree with Ofgem that environmental issues will be a key consideration for this price review. We also agree that the current incentives to provide network infrastructure for renewable generation will be central to this. However, two other issues will also be important in addition to the ones noted by Ofgem in the paper. First, consideration may need to be given to measures to reduce transmission losses. Second, in common with the electricity distribution price review, consideration should be given to allowing some capital expenditure to minimise the impact of overhead lines in areas of natural beauty.

3. Price Control Design Options

User Commitment models

3.1. A key feature of this consultation is a proposal for the introduction of "user commitment models" and we have given careful consideration to these proposals. We agree that there is merit in obtaining some form of user commitment, and the current arrangements in electricity transmission are an example of this. The detailed arrangements need careful consideration to achieve a fair balance of risk and we have set out our further thoughts below.

Background

3.2. In all areas of network charging, there has been a move away from “deep” connection to a system based on “shallow connection plus use of system”. In other words the perceived barrier to entry and other limitations of deep charging have given way to a methodology which shields users from the costs of deeper reinforcement of the transmission and distribution systems.

3.3. Instead, the use of system charging purports to act as a proxy for the deeper long run infrastructure investment required to meet users’ demands.

3.4. Whatever the downside of deep connection, the upside was that it was a very focussed user commitment model. The problem with replacing this with the annualised cost of the deeper investment in the form of locational use of system charges is that the user’s commitment to UoS is only annual and the economic justification for a network investment is quite often on the NPV of a future series of e.g. constraint costs versus the capital investment cost.

3.5. One way to avoid a stranded investment would be to lock in the user to a number of years TNUoS payments. However, this has the downside that if the underwriting period is extensive the financial commitment that the user's financier would have to underwrite starts to look very similar to a deep connection charge. This could also increase the cost and risk to market participants, with negative implications for competition and investment in generation assets.

3.6. A further feature of the deep connection charge in price control terms is that the capital allowance for a transmission licensee is independent of the volume of new users. Simply as new assets are constructed for the users, the users pay for them. This solves the two problems of timing and level of investment that are key to the price control settlement.

Example

3.7. These problems can be illustrated through considering the potential reinforcement of connections to the Scottish Islands to cater for renewable generation. These projects have a considerable capital expenditure, which is only necessary if the generation is constructed. It is therefore clear that some form of user commitment will be required to ensure that the assets are utilised. At present, the commitment is in the form of a "final sums" liability that exposes the generator to the full cost of the transmission infrastructure work if the generator does not connect.

3.8. Once connected, the generator has no further liability, other than the annual use of system charge. However, the fact that a new generation facility has been constructed and will need to generate for a number of years to recoup that investment gives confidence that several years of payments at least can be guaranteed.

3.9. That said, there is still a residual risk that the generator ceases operation a few years after connection. Under the current framework the (stranded) costs of the investment would then be recovered from the generality of users, assuming the generation facility did not continue operations.

3.10. In our view, Ofgem has to strike a balance between exposing general users to the cost of potentially stranded assets and facilitating connection in generation. There is a risk that some form of long term user commitment would, in effect, recreate the barrier to entry for generators that was inherent in the old deep connection arrangements.

Separation of charges from allowed revenue

3.11. In any event, it is clear that user commitment and the associated charges for access to the system should be separated from the revenue increments to the transmission licensees. This is because the lumpy nature of transmission investments makes it very difficult to design a revenue driver that matches the licensees' income requirements. At the point when investment is required, the revenue should increase to fund the investment.

3.12. However, charging arrangements are not designed to exactly match the required increment of revenue required by the transmission company (nor should they since this would approximate to a deep connection charge). In our view, there needs to be a range of charging options available to minimise the risk of stranded assets.

3.13. Where the transmission assets to be provided are largely radial or peripheral there may need to be a longer-term commitment to pay network charges than if the new assets are deeper into the transmission infrastructure. In our view, a financial commitment for say three years ahead, would enable the licensees to review their capital expenditure programme each year based on better information.

3.14. As mentioned above, this financial commitment could be in respect of network charges. However, such a commitment could only be given, in our view, if there was stability of charges over the three years so that users could quantify that obligation.

3.15. In this regard, we continue to have a major concern about the current charging methodologies adopted by NG in both gas and electricity. These charges result in extreme and disproportionate locational signals. As a result the charges are unstable from year to year, and users would be unlikely to be able to commit to a number of years charges unless this instability is addressed.

3.16. A financial commitment arrangement such as this would allow capital expenditures to be optimised within planning timescales. For example, if a generator signalled a reduction in its TEC for the third year a capital investment might be deferred, or other generators waiting to connect might be able to connect earlier. In this way, the most efficient overall investment plan can be developed.

Allocation of investment risk

3.17. Under the current regulatory framework we do not believe transmission companies should be exposed to undue risk in carrying out investment. Once an investment is deemed to be efficient we believe it should be capable of being funded through the normal RAV arrangements.

3.18. However, given the uncertainty regarding the level and timing of investment required for renewable generation, we believe that the TIRG mechanism should be developed to ensure funding for such investments. The possible funding arrangements are discussed further in section 5. Once an investment has been made, as illustrated above, the charging methodology itself assigns the investment risk between different categories of transmission system user.

3.19. Under the current methodology, the generality of network users (and hence, ultimately, consumers) bear the risk of investments becoming stranded through users ceasing to pay TNUoS. A way to avoid this would be to commit new users to financial commitment such as a minimum duration of network charging. However, this minimum period should not be excessively long since this would impose a similar liability as a deep connection charge as mentioned in 3.5 above. In addition, this approach could only be contemplated if the issues about the stability of network charges are resolved.

Conclusion

3.20. In summary, we believe that Users should make a financial commitment (possibly network charges subject to a stable charging methodology) for a number of years, but that this commitment should not be calculated on the basis of recovering the potential deep reinforcement costs. This would be equivalent to a deep connection charge and would unreasonably place all the risk on the user.

3.21. The process for identifying a major reinforcement should be more transparent and funded through a TIRG type mechanism. This process ensures that the network operators have the certainty of RAV funding but are still incentivised to make the most efficient investment.

3.22. We believe this combination results in the most appropriate allocation of risk and incentivises efficient investment.

4. Incentive Options – Electricity

4.1. The issues with the current arrangements identified by Ofgem are the inflexibility of revenue allowances to unanticipated events, and the absence of links between demands for network capacity and revenue allowances. A further issue is the "lumpiness" of transmission investment and the difficulty in designing a revenue driver that adequately rewards the transmission licensee for the investment without transferring the risk to network users.

4.2. However, we believe there are two separate issues here. Firstly, there is the appropriate trigger for investment. In electricity, there are the GBSQSS that sets out both deterministic and economic principles for the provision of network capacity. This means that an ex-ante need for investment can be demonstrated. The need will generally be linked to requirements for capacity indicated by network users – in this case typically new generation. In the current arrangements these new potential users sign onto final sums liabilities which ensures development of the transmission system can proceed in parallel with the generator's process for obtaining planning consent.

4.3. In other words, the existing arrangements in electricity already exhibit the features of "user commitment", since applicants underwrite the network investment through these "final sums" provisions of the CUSC. As discussed above, this could also, if necessary, be enhanced through a further user commitment in the form of a contractual obligation to pay use of system charges for a few years. However, although this mechanism underwrites the investment and demonstrates user commitment, it does not provide the licensee with the additional revenue to fund the project. Maintaining the status quo with this model of user commitment therefore means that there needs to be a means to adjust the revenue of transmission licensees to reflect the investment required to release additional capacity. Section 5 sets out our critique of the different means to adjust the revenue of the transmission licensees and our proposal for a development of the TIRG mechanism.

4.4. The consultation proposes more radical changes to the status quo with a more onerous user commitment model. In our view, there are two key disadvantages of the model described in the consultation. Firstly, as discussed above, it transfers all the investment risk to the user. Secondly, there is an issue about the timing of users' commitment compared to the licensees' obligation to deliver the capacity.

4.5. Users will not be able to commit until they have obtained the necessary consents for their new projects. Furthermore, they often need evidence of a connection offer to obtain consents and secure funding. However, once users have obtained consents, the projects can be constructed relatively quickly, but transmission infrastructure can take several years to construct. A more onerous user commitment model could therefore create a "chicken and egg" scenario whereby new generation cannot commit to connection because they do not have finance/planning in place but cannot obtain the latter without a connection. We believe that such a model could become a significant barrier to entry in the generation market.

4.6. In contrast, the current arrangements are such that users are generally prepared to sign onto final sums liabilities before obtaining consents. This is mainly due to the nature of the final sums obligation where, if the user terminates the agreement, the user is committed only to the extent of the transmission licensee's expenditure to the date of termination and only to the extent that others do not take the capacity. This allows development of the user's project and the transmission system in parallel while limiting the user's financial exposure.

4.7. These current arrangements allowed SSE, in 2002, to start the process for designing and seeking routes for the Beauly-Denny transmission line in response to a growing number of generator connection applications. This essential pre-construction planning and feasibility work was carried out simply in accord with SSE's general duty under the licence to facilitate competition. With a more mechanistic approach in a user commitment model, we might only now be starting this process introducing an unnecessary delay of over three years into the project.

4.8. A change to the user commitment model described in the consultation would require a fundamental change to the charging methodologies and contractual framework. It would also increase the risk for market participants both in terms of delay to projects and potentially introduce a barrier to entry for new generators. At a time when a large number of generators are already in possession of contractually binding connection offers, it is questionable whether a change to a user commitment model can be achieved in practice given that it would affect these contracts and could be open to legal challenge.

Conclusion

4.9. In conclusion, we believe that refinements to the existing mechanism could better produce the outcome that the user commitment model is designed to achieve. In particular a commitment to say 3 years TNUoS payments would signal forward capacity requirements and facilitate timely provision of additional capacity. However, this could be brought forward through a change to the charging methodologies.

Other incentive issues

Interruptions

4.10. At present the three transmission licensees have reliability incentives based on the number of interruptions in the case of the Scottish companies, and MWh lost in the case of NGET. These have been introduced after very little consultation or consideration of whether such an incentive would be likely to affect the behaviour of the licensees and the extent to which licensees are able to manage the system. A particular concern is the asymmetry of the incentive – the Scottish companies would have to achieve zero interruptions to receive a maximum benefit of 0.5% of turnover, whereas periods of bad weather could result in a penalty of 0.75% of turnover. We regard this asymmetry as unacceptable.

4.11. Furthermore, outages arranged by NGET to connect new generators (which are likely to significantly increase in the future) deplete the system and increase the likelihood of supply interruptions which are beyond the control of the TO. If Ofgem intend to introduce an enduring interruptions regime these issues need to be resolved. In particular, the regime needs to be symmetrical and needs to take into account causes of interruption such as whether the system is subject to abnormal weather, or depleted due to planned outages.

Losses

4.12. At present there is no losses incentive in transmission and it is for consideration whether one should be introduced. The type of loss can be categorised as fixed and dynamic losses. The fixed losses are primarily down to the design of the plant and TOs could be incentivised to e.g. purchase low loss transformers to reduce the fixed losses. Dynamic losses are the result of power flows on the transmission system and therefore under the control of the system operator.

Rolling Incentives

4.13. As noted earlier, other initiatives have already been introduced to incentivise capex performance and we believe these rolling incentives should continue to be applied to capex and indeed extended to include opex costs. In particular, we believe the remaining three years of the rolling incentive for the 2000-2005 period should continue as if a full review had taken place rather than a two-year mini review. Also the incentive should be applied to the two-year extension period and continued into the next price control.

IFI and RPZ

4.14. In distribution, incentives have been introduced to encourage innovation and registered power zones. Given the demand for transmission capacity for renewable generation, we believe there is merit in introducing similar IFI and RPZ schemes in transmission.

4.15. 132kV is a distribution voltage in E&W and is therefore presently included in the IFI and RPZ scheme. At the very least, there should therefore be similar arrangements and opportunities for the Scottish 132kV network.

5. Funding Investment in Electricity Transmission

5.1. There are a number of ways to set a revenue allowance for capital investment in a price control context. These are: an ex ante allowance; a revenue driver; cost pass through; or a revenue adjustment mechanism – e.g. TIRG. These options are discussed below and the preferred option developed.

Ex-ante allowance

5.2. The existing price control for SHETL is based on an ex ante allowance for anticipated capital expenditure. Indeed, the same mechanism has been used to set the capital expenditure allowance in each price control since vesting. In a relatively stable investment climate this is an efficient means to set allowed revenues. The historic price controls have also been set in the context of a "deep" connection charging policy so that if there was an unanticipated requirement for a new connection, the licensee could fund this directly through the connection charge rather than through an ex ante allowance.

5.3. The current price control is characterised by a great deal of connection activity for new renewable generation coupled with uncertainty of the timing and extent of investment requirements since these are inextricably linked to the generators' ability to bring their projects to completion. While it is possible, indeed necessary as part of the connection offer process, to identify the transmission investment required to connect the generator, the investment is only necessary provided the generator connects.

5.4. The current charging arrangements are also very "shallow" which means that most of the investment costs are treated as transmission infrastructure and funded through price-controlled revenue rather than connection costs. Consequently, an increment to the price controlled revenue is required to fund the investment.

5.5. It is, nevertheless, possible to develop a range of scenarios for transmission investment to cater for renewable generation. However, whichever scenario is used as a base case for setting ex ante revenue allowances, the only certainty is that it will be wrong, given the scale of the uncertainty. This means that either the licensees will be receiving revenues for investment that has not taken place, or will not be receiving any revenue for an investment that has become necessary.

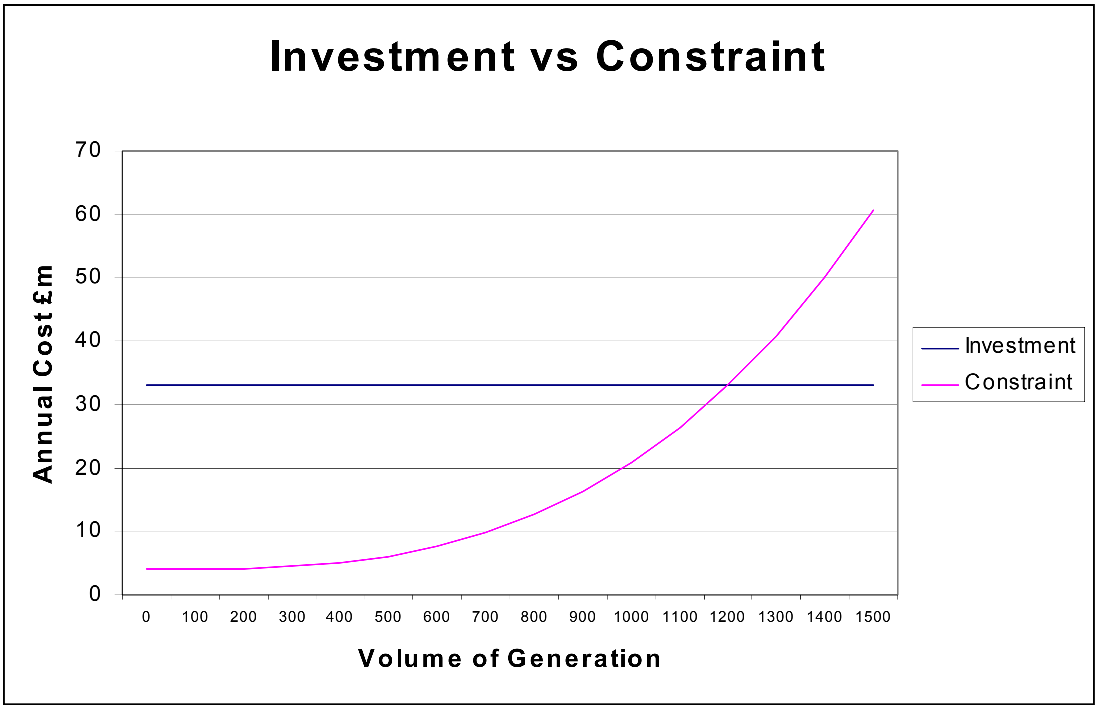
5.6. Such is the range of investment levels compared to historic trends that it is difficult to balance these conflicting interests: firstly of the transmission licensees to ensure that the funding is adequate to cover the investment; and secondly customers who do not want to pay for a planned investment that has not materialised.

5.7. For these reasons we do not believe an ex ante allowance is appropriate for investment to connect new renewable generation in this price control.

Revenue Drivers

5.8. At present, National Grid's revenue allowance is set on an ex ante basis, but supplemented by a revenue driver – the Gt term. This automatically increments the allowed price controlled revenue according to the volume of new generation connecting to the system. At present this is just a broad-brush sum such that wherever the generator connects, the revenue increment is triggered even if the connection location is where there is a deficit in generation and no investment is triggered.

5.9. Clearly there are refinements to this model that could look at more regional or zonal increments linked to the investment requirements in each zone. However, flaws still remain due to the lumpiness of transmission investment. This can be illustrated by looking at the economic benefit of the Beauly-Denny investment as presented in the TIRG final proposals, reproduced in simplified form below with a constrained energy cost of £70/MWh with the costs annualised by application of an illustrative 10% annuity factor.

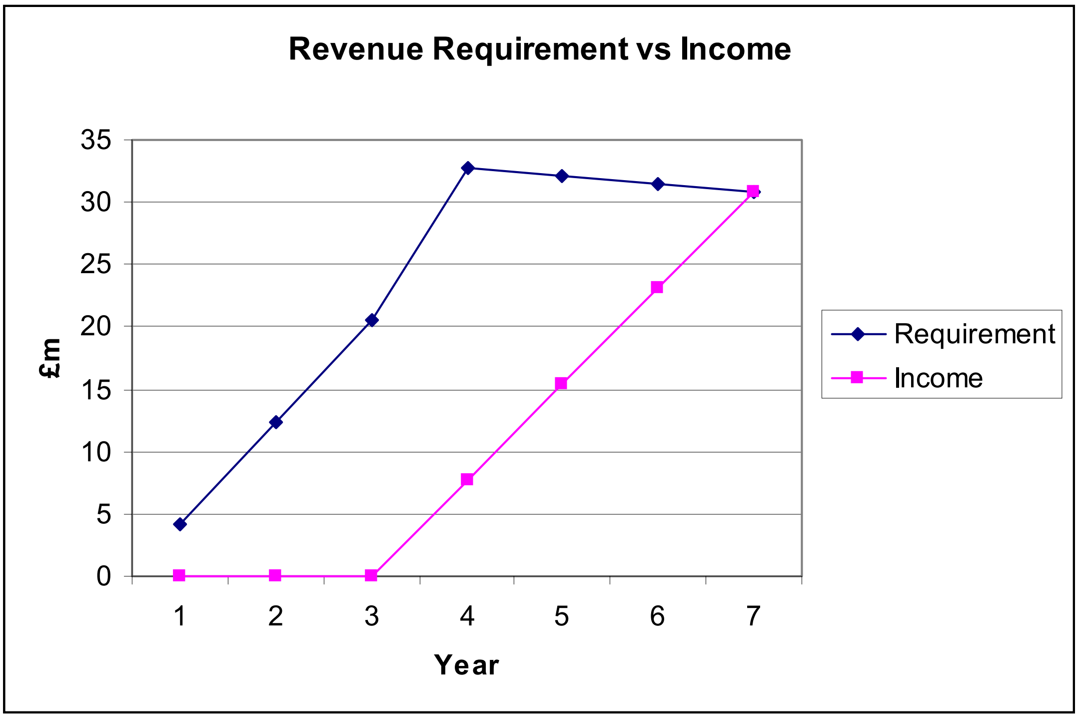


5.10. This illustrates a break even point of 1200MW of additional generation at which point it is equally effective in terms of economic efficiency to constrain generation or construct the line (note that this analysis is based solely on assumptions about constraint costs and not on any technical limitations of the system that may drive investment at a different volume of generation). Construction of the line enables further generation totalling around 1000MW to connect before further upgrades become necessary.

5.11. This implies a "revenue" driver of around £33m per GW of generation, and the allowance would gradually increase to £33m per annum as generation connects into the newly released capacity.

5.12. However, the actual revenue requirement is in two parts. Firstly, for the three-year construction period, revenue equivalent to the cost of capital on the investment to date is needed. After the project is completed, an additional allowance for the depreciation would also be required under the normal price control principles.

5.13. The revenue driver, even if perfectly matched between the capital cost of the project and the MW capacity released, results in a significant mismatch between the revenue requirements of the TO and the revenue obtained through the revenue driver. This is illustrated in the graph below.



5.14. In years one to three, no new generation connects, and in the subsequent four years, the capacity is gradually filled at a rate of 250MW per year. If capacity could be provided to exactly match the generators' requirement, then the revenue driver would provide the right level of income. However, because the investment is required in advance of the first generator connection, and because the investment delivers much more than the initial increment of capacity required, there is a very large funding gap amounting to some £90m before any adjustments for interest.

5.15. This shows that with a revenue driver that is set with perfect foresight in terms of the £/MW incremental cost of the investment there will be a very large funding gap to be addressed. Clearly this could be done at the periodic price controls and the allowances "trued up". However, this would be a considerable risk for the licensee because it would be forced to demonstrate at that review that the investment was economic and would have to negotiate the truing up allowance from a position of already having committed the investment. This is unacceptable. Indeed, if Ofgem have to in any event approve this "trued up" allowance, this defeats the objective of an automatic revenue driver that does not require Ofgem approval.

5.16. There is therefore a real risk that a mechanism based on revenue drivers would incentivise transmission licensees to delay or defer investment beyond the point where it is efficient to commence work. In the context of providing infrastructure to facilitate new renewable generation, this could in turn have implications for Government environmental aspirations and wider security of supply.

5.17. A further refinement suggested in the consultation is for a more zonal revenue driver. To calculate such zonal drivers would require all the potential zonal investments to be identified and a zonal driver calculated. Since Ofgem would require to sign on to such a zonal figure based on the forecast cost, Ofgem would in effect be "approving" each identified project. The zonal driver approach would appear to have the same drawback of Ofgem "approval" as identified for the TIRG mechanism, without dealing with the funding gap issues identified above.

5.18. In this regard, we would note that the equivalent process in the gas entry auctions to set new UCAs has been particularly inefficient and has led to unintended outcomes. We believe that these issues could be even more significant in the context of electricity transmission investments, given the wide variation in cost/MW of individual projects.

5.19. It is also clear that a scheme based on revenue drivers would require a complex set of ancillary arrangements in relation to, for example, incentive scheme caps, collars and sharing factors. Again, this not only introduces significant additional complexity, but also risks unintended consequences. The level of the scheme parameters would clearly drive licensees' behaviour and there could be an additional risk that if these parameters are set at an inappropriate level (whatever that might be) otherwise efficient investment may be deferred.

5.20. We do not therefore believe that a revenue driver approach, even with the zonal refinements suggested in the consultation is workable in practice.

Cost pass through

5.21. Cost pass through is a mechanism used for a number of cost items in the price control. However, they have a common feature in that they are generally not controllable by the licensee. These include rates and licence fees for example.

5.22. Cost pass through could be used in the context of transmission investment but we do not believe this would be in the interests of customers, since there are no incentive properties associated with cost pass through. It is for this very reason that the traditional pass through items are uncontrollable costs.

5.23. The licensees would also be at risk at the periodic reviews of some of their investments being deemed to be uneconomic and disallowed.

Revenue Adjustment Mechanisms

5.24. The final means of setting revenue requirements is through some form of revenue adjusting mechanism. In this context we would class the existing "TIRG" term in the transmission licence as a revenue adjusting mechanism. We believe that this is capable of being used and developed for future large investments.

5.25. The TIRG term came about as a result of the Ofgem review of transmission investment for renewable generation. The process involved the transmission licensees identifying a number of major transmission reinforcements that would be required to enable the significant volume of renewable generation to connect. Ofgem's consultants reviewed the transmission licensees plans for these major network investments in terms of the economic efficiency of the investment, whether there was sufficient evidence of new generators to allow the licensees to progress with the projects and the additional capacity released.

5.26. Where a project passes both these tests of economic efficiency and demonstrated need, the projects are classed as "baseline" and eligible for funding. On the basis of this review, some projects were classed by Ofgem as baseline and funding released through a licence modification. This modification ensures that funding is only released when construction actually commences, and funding is only in respect of the capital expenditure forecast made by the licensee at the time of the economic assessment, subject to review of costs should the detailed planning and consent process oblige the licensee to incur unforeseen costs. This means that the normal features of RPI-X regulation are retained.

5.27. The features of the TIRG term are therefore that:

- the efficient investment to release the required capacity is identified in terms of a project definition;
- the project outputs are identified in terms of capacity released;
- the spend profile is identified;
- a revenue allowance is released from the start of actual construction of the project; and
- the licensee is incentivised to construct the project below the forecast level of spend.

5.28. Unlike the ex ante approach, there is no risk of setting a revenue allowance too high or too low with the inherent inefficiencies. Any project submitted to Ofgem for inclusion within TIRG would be subject to the usual scrutiny one expects at price control reviews (by, for example, review by expert engineering consultants). There is also no risk that the investment is inappropriately delayed, since, once the project is identified, it could be approved and progressed relatively quickly (as was the case with the Beauly-Denny line)

5.29. Unlike the revenue driver approach, the revenues under a TIRG mechanism would match the actual investment rather than the incremental capacity release, avoiding the risks associated with truing up the income at periodic reviews. Again, this negates any possible incentive to inappropriately delay investment.

5.30. Unlike cost pass through, the TIRG mechanism ensures that the usual efficiency incentives in RPI-X regulation are retained. A TIRG mechanism also limits the risk for the transmission licensee in that ex ante "approval" of the investment is obtained.

5.31. A possible criticism of the TIRG mechanism is that the licensee must approach Ofgem with the details of each project for the revenue adjustment term to be designed. However, even in areas where a revenue driver funding mechanism has been implemented, (such as gas entry) there is evidence that the licensee still requires Ofgem approval before committing to expenditure.

5.32. An example is the approval of investment in the gas transmission system to connect the Aldborough gas storage facility. This required the calculation of a unique "revenue driver" obtained, in effect by reverse engineering from the forecast capital expenditure, followed by ex-ante approval by Ofgem of National Grid NTS's (NGNTS) capex.

5.33. This possible drawback is therefore not unique to the TIRG mechanism. We also believe that the number of projects involved in a TIRG mechanism would be small – a handful of projects for each licensee over the five year period. We therefore do not consider that any concern about Ofgem approval of individual schemes provides sufficient justification for adopting a revenue driver approach, with all of the attendant problems.

5.34. Recognising this issue, we believe that there is a balance to be sought as to the scale of project that might qualify for a "TIRG" funding mechanism, and those which should simply be constructed as "business as usual", funded through the normal ex ante transmission revenue allowance.

5.35. In addition, we believe that the "business as usual" ex-ante capex revenue allowance should cover all the costs of load related expenditure at the more local infrastructure level. This would include, for example the costs of progressing planning and consenting of lines identified in the connection offers as well as the generator specific local infrastructure. Major projects qualifying for TIRG type funding would only be those nominated major projects identified as requiring specific funding due to the uncertainty regarding need (driven by user connections) and timing. The ex-ante capex allowance should also cover programmed asset replacement in the usual way.

Conclusions

5.36. We believe that ex ante allowances, cost drivers and cost pass through mechanism all have significant failings in setting revenue allowances for major, user-driven, transmission investments. None of these arrangements can share the investment risk equitable between licensees and customers, nor can they deal with the uncertainty of timing and level of expenditure required in the price control. There is also a concern that these mechanisms will lead to an inappropriate delay in bringing forward otherwise efficient investments

5.37. A revenue adjustment mechanism, as currently characterised by the TIRG allowance, allows revenues to adjust only when investment takes place; ensures an efficient level of investment; and retains efficiency incentives on the licensees.

5.38. Given that these TIRG licence adjustments will only take place for a very small number of projects, we believe that this is the right way forward for the price control.

6. Incentive Options – Gas Entry

Introduction

6.1. Ofgem’s December 2000 conclusions paper on the long term signals and incentives for investment in gas transmission capacity reiterated the objectives of the reform entry arrangements and, therefore, the auction framework that is now in operation. These objectives are to:

- promote the economic and efficient, longer term development of the NTS to meet the needs of the users of the NTS and ultimately, gas consumers; and
- ensure that the capacity rights are sold in a non-discriminatory manner that does not distort competition in related markets, such as the supply of gas.

6.2. It is therefore against these two points that the success or otherwise of the regime should be assessed. This paper reviews the entry arrangements against these objectives.

Investment signals.

6.3. The first objective relates to the generation of investment signals to enable NGNTS to make appropriate decisions about where, when and how much investment is required at the NTS system entry points. The regime has been based upon the premise that additional growth is required at existing terminals. However, as Ofgem explained at the incentives workshop, to date no investment signal has been received by NGNTS for existing entry points. The only investment signals that have been received are for the creation of new entry points to accommodate new storage facilities and LNG import terminals. Applications for these new entry points would, of course, have been received whatever the arrangements for allocating capacity on the existing system.

6.4. From the outcome of the auction process therefore, in terms of the existing entry points, it could be argued that, quite simply, no extra investment at existing terminals is required. However, NGNTS's assessment of future capacity requirements (TBE 2005) showed that all supply scenarios going forward are significantly above those that would be suggested from the long term auction bids seen to date. Furthermore, NGNTS's forecasts would indicate that future demand at key entry terminals is expected to exceed current baselines indicating that incremental capacity is in fact required. It would appear therefore that, contrary to NGNTS's expectation of investment requirements ascertained through its TBE process, the auction regime has failed to provide NGNTS with any investment signal at existing terminals. Indeed, it has not even resulted in the allocation of existing capacity in the longer term to meet supply scenarios.

6.5. Turning now to the creation of new entry points. Following the introduction of the auction the regime, a new entry point can only be created if NGNTS receives an investment signal through the auction process. Therefore, it is unsurprising that NGNTS has received such signals from the process. However, in order for this to take place, it is evident that the process has to be choreographed to meet the needs of the regime. That is, following due process, Ofgem has to propose modifications to reopen NGNTS's NTS price control to insert the anticipated new entry point and assign to it an Unit Cost Allowance (UCAG) to facilitate the process. Thereafter, a shipper(s) acting on behalf of the developer has to calculate the bids that would be required to meet the economic test. They then bid accordingly and, assuming no errors were made, NGNTS commits to providing the capacity.

6.6. Although the auction process could be deemed to have "worked" for the provision of investment signals for new entry points, we do not believe that it is an efficient way to deal with what is, essentially, a new connection. Furthermore, for new storage points it has created a number of issues relating to the interaction of the NTS entry and exit capacity regimes going forward. For example, although a new storage development has paid for its connection through the entry capacity auction process described above, discussions would suggest that there is a risk that it is deemed to have a zero capacity entitlement for exit capacity purposes. Clearly this is not correct since the connection/capacity that has been paid for and provided under the entry auction process is the same as that used for delivering gas to the storage facility. This issue has been raised by the industry on a number of occasions but, to date, its resolution remains outstanding.

6.7. A revenue driver is entirely unsuited to the lumpy investments required in transmission. There is evidence of this in NGNTS's report on NTS SO incentive performance to date. This report indicates that there has been no investment between 2002/3 and 2004/5 in entry capacity. Instead NGNTS have been rewarded by some £70m under the revenue driver for investment in capacity that has not in fact taken place. Presumably this is because the increment of capacity requested by users has not reached the point at which investment is triggered. The revenue driver therefore significantly over compensates NGNTS for the incremental capacity and we believe this is inefficient.

Non-discrimination and impact on competition

6.8. Turning to the second objective, we agree that an assessment of the regime could conclude that under the auction regime capacity is allocated on non-discriminatory terms to existing users of the system. However, it is also necessary to consider whether the auction regime has had an impact on competition in the relevant markets.

6.9. In assessing this, there are a number of areas to consider, complexity, charging stability and regulatory stability.

Complexity.

6.10. The auction regime is operationally more complex than the previous regime and shippers need to understand and have the capability of participating in a series of long term, annual and short term auctions. However, shippers also need to be able to monitor and anticipate the impact of the NTS entry auctions on other aspects of the regime in order to assess their overall position. For example, the buyback incentive scheme and both the capacity and Transmission Operator (TO) commodity neutrality arrangements. While it must be expected that a participant within a certain market should be able to understand the environment within which it operates we believe that the added complexity of the capacity auction regime is, in effect, a barrier to entry.

6.11. In addition, the more complex a regime the higher the risk and cost to the participants. We therefore believe that the complexity of the regime has not only had an impact on competition in terms of new entrants entering the market, we also believe that it has contributed to an increase in the cost of the gas trading arrangements. The degree to which shippers/suppliers are able to absorb these additional costs/risks will have undoubtedly have influenced their appetite to compete in the auction regime as well as their competitiveness within the market. For example, we believe that some of the liquidity problems in the wholesale gas market can in part be attributed to Ofgem's entry auction regime, which directly discourages (because of the risk and complexity) participation in the market for beach supplies.

Transportation Charging Stability.

6.12. Shipper/suppliers want stability to enable them to set customer charges. The extent to which they are able to accurately predict the transportation charge and reflect those in their customer charges will inevitably have a direct impact on their ability to compete in the market.

6.13. However, the auction regime means that the NTS entry capacity charge paid by a shipper for any one-day is a function of the outturn (in terms of volume and price) of the suite of auctions that the shipper has participated in over, potentially, a period of some sixteen years. In other words, the entry capacity transportation charge is no longer a stable, predictable, administered and uniformly applied number to be factored into charges to customers. Rather, it varies considerably depending upon not only an individual shipper's strategy but also that of other shippers within the capacity "market".

6.14. One could argue that in order to avoid this uncertainty, shippers should lock in their capacity charges through the long-term auctions. However, the ability to do this depends upon the nature of the upstream gas contract for which the capacity is required many of which were entered into before the auction regime was introduced. Furthermore, a downstream shipper is in a very different position to an upstream, affiliated shipper in this respect. We would argue, therefore, that the auction regime has discriminated in favour of the affiliated, vertically integrated shipper who has far greater access to upstream information and does not have the same contractual restrictions as their downstream competitors.

6.15. There is a second transportation charging issue that must be considered when assessing the impact of the auction regime on competition. That is the need for an over/under recovery mechanism where auction revenues do not match the regulated NTS entry capacity allowed revenue. Currently, where there is an under recovery, the short fall is made up by the application of a TO commodity charge levied on gas flows through an entry terminal. Where there is an over-recovery, the excess is passed back to shippers in proportion to their capacity holdings. In other words, the adjustment mechanism adds a further layer of complexity to the charging regime and makes it less predictable for shippers and, therefore, their ability to accurately predict their own charges is further diminished.

6.16. Furthermore, in effect, the over/under recovery mechanisms redistribute transportation revenues between shippers depending on the outcome of the auction regime and depending on a shipper's relative position within the market. In other words, it could be viewed as a windfall tax or benefit depending on a shipper's relative position in the market which further distorts competition.

6.17. In other words, since the introduction of the auction regime transportation charges are no longer a stable, "boring" element of a shipper/supplier's considerations, they have become an added risk with an associated impact on competition.

Regulatory Stability.

6.18. Stability of the regulatory regime within which the long-term auctions operate is also essential if the objectives of the long-term auction regime are to be met.

6.19. However, a number of significant regulatory changes have already been made to the regime that have created considerable uncertainty. In particular, the ability of the NTS to limit the amount of obligated capacity (i.e. baseline plus any obligated incremental capacity) it offers for sale; and the ability to change the investment lead times. Furthermore, there is an expectation that other key elements of the regime are likely to change following the NTS price control review, including the baseline quantities of NTS entry capacity at each NTS entry point and profound changes to the associated UCAGs. The latter being due, it would appear, to significant shortfalls in NGNTS's forecasting ability at the time the UCAGs were set.

6.20. Our concern with the above changes stems from the fact that each of the above elements are fundamental building blocks of the auction regime that were incorporated into the NTS licence. Accordingly, shippers participating in the auctions to date have based their commercial decisions and bidding strategies for procuring NTS entry capacity on these parameters and "rules". Therefore, any change to these aspects of the regime will, inevitably, undermine those decisions and strategies and ultimately have the effect of changing shippers' relative commercial position within the market. In other words, changes of this kind are likely to significantly distort competition. Risks of this sort will also deter shippers from participating in future long-term auctions thereby foregoing the emergence of any investment signal for the NTS.

Conclusions

6.21. We are concerned that the auction regime has not been successful in meeting the stated objectives of a long-term regime. In our view, the above analysis shows that the auction regime has not delivered against its two main objectives. In particular, it has not provided NGNTS with any robust investment signals. In addition, we consider that there is compelling evidence to suggest that the auction regime has distorted competition, unnecessarily increased perceptions of risk in operating in the competitive gas market and has required frequent, unanticipated regulatory intervention to solve problems that have emerged from the complex auction arrangements.

6.22. We have detailed above in our comments on incentive options in electricity the shortcomings of the revenue driver approach. We have also discussed above the failings of the current auction regime. None of the options presented by Ofgem for entry would deal with the issues with the current arrangements.

6.23. In our view, the auction regime should therefore be replaced by an application process for capacity, with prices set at the long run cost of additional capacity calculated using an approved methodology. The effectively de-links the access and charging arrangements from the revenue requirements of NGNTS for funding investment. This should be supplemented by a commitment to pay the capacity charge for a minimum period. NGNTS can then determine whether to invest in additional capacity or whether to manage the capacity requirements through buy-back.

6.24. If, however, Ofgem determines for wider policy reasons that the auction regime should remain at entry points, we believe that there should be minimum change to the arrangements. Any further changes would undermine investors' confidence in the market arrangements.

6.25. In particular, we do not believe that it would be appropriate to redefine the baseline quantities at each entry point. To do so would, in our view, undermine a key parameter of the regime against which market participants who have participated in the long-term auctions have assessed their position and made commercial commitments. Ofgem's main objective to review how baselines are set appears to be based upon a concern that unsold baseline capacity is potentially sterilised under the current arrangements.

6.26. However, we would expect NGNTS to consider whether unsold entry capacity at one location can be released to another (i.e. the perceived benefit of moving to a zonal baseline) as part of its allocation decision making process. That is, as an efficient and economic operator if its system, NGNTS should automatically be making these trade offs in deciding whether it needs to invest or not. We do not therefore believe that it is necessary or appropriate to revise the baselines as by doing so would, in effect, transfer all of the risk to market participants and away from the regulated monopoly who is best placed to make these decisions.

6.27. We also note from recently published information on NGNTS's system operation performance, that its exposure to buybacks has been very minimal. In other words, it would not appear that the way in which the baselines have been set to date have caused any adverse cost exposure to NGNTS and/or the industry. To the extent that the baselines cause an under recovery at some entry points is, we believe, a charging issue and is not related to the physical assets that are already in the ground.

7. Incentive Options - Gas Exit

Introduction

7.1. Ofgem’s proposals for the enduring gas exit arrangements are modelled on the gas entry arrangements. That is Gas Distribution Networks Operators (GDNOs) and Transmission Connected Customers (TCCs, through their shippers) would participate in a series of volume and price based auctions for securing their exit capacity requirements.

7.2. Our comments on the entry capacity regime in section 6 have highlighted our concerns with auctions at entry and in general terms. However, in our view, the introduction of an auction regime for the allocation of exit capacity raises a number of additional issues that together provide even more compelling reasons to reconsider Ofgem's preferred approach. We have set out these below.

7.3. When compared to entry capacity, exit arrangements are greatly different in terms of the number of exit points and the nature of user, and therefore require a different approach.

7.4. The key difference is that entry is characterised by a small number of entry points with a relatively large number of shippers competing for capacity. At exit, however, there are a large number of exit points with, in the main, only a single user. This means that to ensure an effective level of competition to drive market signals, determine an efficient value and allocate capacity that Ofgem believes is necessary, some form of zonal aggregation will be required. This could be achieved by either defining a zonal baseline/product or via the inclusion of a substitution regime within a nodal system, the effect being the same.

Zones and investment signals.

7.5. The extent to which the NTS could be divided up into zones has yet to be identified. However, it is apparent that significant zonal aggregation would weaken any physical and location signal for the NTS. This has been argued by NGNTS on a number of occasions. Some other mechanism would then be required on top of that to identify where exactly the investment was required thus adding a further layer of complexity.

GDNOs competing with commercial organisations

7.6. However, zonal aggregation introduces a further risk that has not been an issue at entry. That is, in that different types of users could be competing for the available capacity. Ordinarily, this may not be an issue. However, for exit capacity purposes it is, since a situation would arise where a regulated gas distribution network operator (GDNO) would be competing with a directly connected users (e.g. a power station). Given that the commercial frameworks and obligations of each are quite different we do not believe that this arrangement would be acceptable. The power station would be bidding according to the value it placed on the capacity, whereas the GDNO would have its statutory obligations to comply with the "1 in 20" demand scenario which has to be met within a defined revenue allowance.

7.7. Failure of the power station to secure adequate capacity simply undermines its commercial position, whereas failure of the GDNO to secure capacity could place it in breach of the Gas Act. In other words, the consequences of "failing" to secure capacity through the auction mechanism are very different, one being a risk of commercial exposure, the other a breach of statutory obligation. It is therefore necessary to consider what the impact of these different risks would be.

Bidding

7.8. A GDNO is a regulated monopoly with a set revenue allowance. This revenue allowance would need to include a pass through of the costs it incurs for the procurement of capacity in the various auctions. However, a generator does not have this regulatory protection and therefore would argue that for them to have to compete with the regulated entity automatically puts them at a disadvantage. In other words, the GDNO is in a situation whereby if it fails to procure its capacity, it fails to meet its statutory duty. Whereas if it bids to ensure it meets its statutory requirement commercial organisations would be likely to appeal that the regime is stacked against them since the cost to the GDNO is, essentially, passed through to customers.

7.9. We do not see any way of avoiding the resultant distortion to bidding in the auction, since it is inherent in the incentive design. Exit reform will therefore be likely to lead to a sub-optimal allocation of capacity and an increased risk for all market participants.

Self sufficiency

7.10. A further consequence of introducing a competitive commercial arrangement is, we believe, a tendency for GDNOs to move to becoming increasingly independent of the NTS. That is, when faced with the risk of fluctuating demand and the need to compete with other organisations, over time, we believe the GDNOs will be driven towards becoming as self-sufficient as possible, which may not necessarily be an efficient or economic outcome.

Allocation of Risk

7.11. An auction regime at exit would, in our view, create a shift change in the allocation of investment risk. In effect, auctions would de-risk NGNTS's exit capacity investment programme since all of its investments would be underwritten by GDNOs or by TCC shippers through the auction process. We do not believe that this is appropriate. In this regard, we also note Ofgem's recent decision to veto NGNTS's version of the IExCR methodology that provided for complete investment underwriting by users of the NTS. Other than the immediate commercial benefit to NGNTS, we are unaware of any apparent justification or benefit to customers of this proposed transfer of risk.

Complexity and unforeseen consequences

7.12. The introduction of an auction regime would represent wholesale change to the existing regulatory and commercial exit framework. At its simplest, the proposed regime represents the creation of a new market to deal with something that, hitherto, has been managed by an administered regime with regulatory oversight. A change such as this will inevitably be accompanied by an increase in uncertainty and a perception of risk which we do not believe is in the interest of consumers at a time when gas supplies and prices are so uncertain. We also believe that exit reform would have a particularly profound effect on interconnectors and storage facilities that are vital to UK security of supply. Rather than introducing further complexity, uncertainty and risk we believe the gas supply chain is in need of as much stability as possible at this time.

7.13. We are also mindful that the impact the proposed reform would not be confined to the gas market. Given the interactions of the gas and electricity markets we believe that it is inevitable that there will be a knock-on effect to the gas fired generation market, the extent of which has not yet been quantified. We are not sure that these costs and risks have been factored in to the initial cost benefit analysis that Ofgem undertook as part of the DN sales process. Certainly, Ofgem has asked that any consequential costs be excluded from the cost gathering exercise currently being undertaken which we believe is inappropriate.

7.14. While the overview of the proposed auction regime is not necessarily that complex, we know from the experience of the entry capacity regime that the commercial business rules, the licence framework and incentive structure that is required to support the auction arrangements are very complex indeed. Since the proposed enduring arrangements seeks to introduce an auction regime for two products, flat and flexibility capacity, and without even considering the interactions of these two products, it is apparent that the complexity of the combined entry and exit arrangements going forward would be extreme. The introduction of new arrangements always carries a risk of unintended consequences the probability of which is far greater the more complex the changes are being made. We are therefore extremely concerned that the potential for unforeseen consequences going forward is very high.

Conclusion

7.15. For all of the above reasons, we believe the introduction of an auction regime at exit for the enduring arrangements is flawed. However, in recognition of Ofgem's belief that reform is necessary, in the following section we have set out what we believe are the driving forces behind Ofgem's key objectives for exit reform. Thereafter, we have developed an alternative proposal that we believe delivers Ofgem's objectives but which we believe is a more measured approach and avoids many of the issues we have discussed thus far.

8. Background to Ofgem's Proposals for Exit Reform

8.1. Ofgem has stated that the reform of exit arrangements must enable NGNTS to assess users' requirements for capacity and meet the following objectives:

- there should be efficient investment in both transmission and distribution networks compliant with legal requirement regarding security of supply;
- there should be an appropriate allocation of risk between NGNTS, DNOs, shippers and directly connected customers; and
- the arrangements should be simple and transparent.

We have considered each in turn below.

Efficiency

8.2. In essence, the first objective means that the enduring exit arrangements must provide information to NGNTS on the capacity requirements of the GDNOs and TCCs. The information must be provided within timeframes that allows NGNTS to plan and invest in the network to meet these various requirements. However, the arrangements must ensure the GDNOs make the most efficient decision on how to meet its flexibility requirements and to ensure that it does not, in effect "free-ride" on the NTS, to its cost and potentially to the disadvantage of other users.

8.3. Both the NTS and GDNOs have a "1 in 20" obligation regarding security of supply. This means the gas requirements should be forecast on the basis of the coldest peak day that might be expected once every 20 years. A failure to meet this obligation would be a breach under the Gas Act and there would be severe penalties for such breach. In order to meet its obligation therefore, the NTS needs information from both TCCs and GDNOs on their capacity requirements so that it can develop its system in the most efficient manner to meet those joint requirements.

8.4. Under the current arrangements, GDNOs are required to forecast their 1 in 20 requirements on a rolling 10-year basis. In addition, more specific and detailed forecasts are made for both flat capacity and flexibility (diurnal storage) requirements on a 5 yearly basis by offtake. A GDNO's flat capacity requirements can realistically only be met by NTS capacity at each offtake and, therefore, a GDNO's needs in this respect are relatively straightforward.

8.5. However, a GDNO also needs to manage within day demand variations on its network. To do this it has a number of potential options available to it. It can build storage or other short-term flexibility tools within its own network, enter into interruptible contracts or it can use the flexibility capability of the NTS. In other words, to some degree the GDNO can choose how it meets its flexibility requirements. We would question how material these arbitrage opportunities are in practice. Nevertheless it is this potential arbitrage ability that underpinned Ofgem's first objective above, the efficiency objective, during the DN sales process. In other words, following DN sales, Ofgem firmly believes that a "price" must be attached to each of the GDNO's options to enable it to make the "right" decision on how it would most efficiently meet its flexibility requirements.

8.6. Similarly, TCCs need to provide information to NGNTS on their capacity requirements both in terms of their flat capacity requirements and the extent to which they require the ability to increase/decrease their flow rates within day – their flexibility requirements. Currently, this is provided by both TCCs and their associated shippers via the capacity registration mechanism, the NExA and ARCA arrangements. They also provide long term information via the TBE process. The Uniform Network Code also has provision within it for TCCs to provide, voluntarily, more detailed information on a 5 yearly basis. Between them, these mechanisms provide information to the NGNTS on TCC's requirements for both flat capacity (via the registration process) and flexibility (through the NExA provisions).

8.7. It therefore appears to us that the only issue that is potentially not addressed by the current arrangements is the explicit signal of a cost to the NTS products used by the GDNO so that it can make the efficiency trade offs so desired by Ofgem.

Appropriate allocation of risk

8.8. Turning now to the second objective, Ofgem believe that the enduring arrangements should also ensure that there is an appropriate allocation of risk between NGNTS, GDNOs and TCCs. We would agree with this principle and believe that the balance of risk under the current arrangements is proportionate. Certainly, we do not believe that it would be appropriate for there to be a wholesale transfer of risk from one regulated monopoly to another (i.e. from NGNTS to GNDOs). We also believe that it is necessary to consider the allocation of risk between the commercial entities, i.e. TCCs and regulated monopolies given that their ability to mitigate various risks are entirely different. This feeds in to the consideration of whether it is necessary, or indeed appropriate, to have identical allocation arrangements for TCCs and GDNOs in the enduring arrangements.

Simplicity and transparency

8.9. Ofgem's final objective relates to the requirement for the enduring arrangements to be simple and transparent. In other words, a move towards a more complex set of arrangements would have to be fully justified in terms of actual benefits when judged against immediate as well as the consequential costs of reform and the potential for unforeseen consequences.

9. Proposals for Enduring Gas Exit Arrangements

9.1. Against the above discussion, we have set out below a version of an enduring exit arrangement that would, in our view, overcome the complexities and issues associated with Ofgem's preferred auction arrangements, while recognising the need to meet each of Ofgem's key objectives.

User requirements - Capacity forecasting

9.2. It is evident that future arrangements need to ensure that GDNOs and TCCs consider their capacity requirements and provide that information to NGNTS within appropriate timeframes to enable NGNTS to plan how best to meet these requirements. In other words, consistency in the provision of information is required, not necessarily consistency in how that information is given. Accordingly, we do not believe that it is necessary or appropriate for the GDNOs and TCCs to have identical arrangements particularly since they are very different types of user. Consistent with these views, we believe that the following arrangements provide a viable alternative to Ofgem's enduring exit arrangements.

9.3. In accordance with the GDNO's statutory requirements and the existing rolling planning arrangements, the GDNO would carry out long term planning forecasts to identify its offtake capacity needs. These would then be submitted to NGNTS for an assessment of its ability to meet these needs. In the event that the NTS determined that investment was required to meet those requests and the investment was attributable to that particular GDNO's capacity submissions, NGNTS would prepare and provide to the GDNO an estimated project cost and timing of providing that incremental capacity.

9.4. To the extent that the GDNO is able to meet that incremental capacity requirement from other means, e.g. by investing in its own network or by contracting for interruption, it would make an assessment of the cost of those alternatives which it would then compare with the project cost it had received from NGNTS. Thus, the GDNO is able to make an efficient decision of how to meet its capacity requirements. In the event that the most efficient decision is to request that incremental investment from NGNTS, it formalises its request with a firm "booking" which NGNTS commits to and invests accordingly (thereby meeting its 1 in 20 obligation). At future price control reviews therefore, both NGNTS and the GDNOs would have sufficient evidence through compliance with this process to support their investment decisions.

9.5. To the extent that this needs to backed by some form of user commitment, an ARCA type arrangements could be considered with appropriate cost pass-through arrangements. Clearly, under any ARCA mechanism, the allocation of risk between the two regulated monopolies would need to be proportionate.

9.6. However, the NGNTS also needs to be aware of any decrements of offtake capacity requirements. Clearly, the planning process above would also identify circumstances where the GDNO is seeking less offtake capacity than hitherto had been required. Statutory obligations, incentive mechanisms discussed later in this section and existing Standard Special Condition A17 (General obligations in respect of gas transporters' pipe-line systems) together would ensure that the GDNO requests an appropriate amount of capacity.

9.7. The arrangements for TCCs and the way in which they would provide information to NGNTS to enable it to make efficient investment decisions used to be slightly different to the GDNOs. In our view, the existing combination of capacity registration, NExA and ARCA already does this for both existing and new connectees. The NExA sets out the parameters of that offtake, the registration process provides the information that the capacity is still required and the ARCA provides a mechanism for increasing the parameters to the extent that incremental/new capacity or flow rate variation is required. It also provides a commitment outwith the one-year registration window. To the extent that, after due consultation, it is identified that there is merit in extending the current registration period, we believe that it would be relatively simple to make necessary changes. Alternatively, or in addition, existing UNC requirements for the provision of information from TCCs to NGNTS could be enhanced to provide information over a longer timeframe.

Efficient Investment - Incentives

9.8. The above measures would ensure that there is a mechanism for GDNOs and TCCs to signal their capacity requirements over a reasonable timeframe. We also believe it would provide a means for GDNOs to weigh up the options available to them to meet their requirements and to ensure they are met in the most efficient way.

9.9. It might be argued that a GDNO's natural tendency would be to want to invest in its own system, as by doing so it increases its self-sufficiency and grows its asset base. Clearly appropriate incentives already exist within the price control process to protect against this. In particular, if a GDNO is unable to justify its cost, Ofgem would disallow those costs at the next price control review.

9.10. The above arrangement for sharing information would provide network owners and Ofgem with cost information on the alternatives of meeting capacity requirements and therefore, the necessary comfort that a mechanism exists to demonstrate that appropriate “trade offs” have been made by the relevant GDNO when deciding when/where to invest. Likewise, it would provide documentation to support any NGNTS decision to invest.

9.11. These enhanced regulatory oversight measures would be similar to Ofgem's interest in, for example, overseeing long term asset management through ARM or PAS-55 processes and would certainly be no more onerous than that work.

9.12. However, we believe that these two aspects of the above proposal could be further enhanced by input based regulation and output incentive arrangements. For example, certain input planning criteria could be established to ensure that potential investment costs are derived. This would provide a consistent approach across all networks and therefore facilitate the most efficient investment decision being made. It would also provide a straightforward and simple way for Ofgem to audit the investment decisions that had been made. Similarly, forecasting models could be examined/audited.

9.13. Furthermore, we believe that it would be relatively straightforward to devise an incentive mechanism for the GDNOs to further encourage them to make the right decisions. For example, we believe that a simple quality of supply incentive scheme could be introduced along similar lines as the IIP scheme in electricity distribution. This is a sliding scale mechanism with rewards and penalties for performance against pre-set targets subject to caps and collars.

9.14. In the context of gas distribution, such a scheme could take the form of a target performance against a basket of quality of supply indicators, possibly including, for example, some of the existing standards of performance. It could also include a target in relation to NTS exit capacity to further incentivise GDNOs to minimise those costs, although the setting of any such target would need to be done on the basis of a more robust methodology than Ofgem used in setting the targets for the interim arrangements.

9.15. Given that Ofgem is keen to ensure that the GDNO makes efficient trade-offs in deciding how to meet its diurnal storage requirements, another possibility would to consider the application of output incentives. For example, it might be possible to compile an inventory of how the GDNO meets its diurnal storage requirements. The extent to which the makeup of that inventory (and, therefore, the overall cost) varies over time could be monitored and an incentive applied. This would, we believe, address any concerns Ofgem may have over the possibility that a GDNO may decommission storage assets on its own network for operational savings purposes yet perhaps increasing its request for flex from the NTS which could be inefficient.

9.16. In any event, to ensure that there is a balance of risk, it would also be necessary to have reciprocal incentives applied to NGNTS. This may take the form of an incentive to deliver projects on time and to budget particularly since a failure by NGNTS to meet investment targets could mean a GDNO is unable to meet its 1 in 20 obligation. It too could be subject to a forecasting incentive to ensure that both NGNTS and GDNOs behave appropriately and minimises the potential for forecasting discrepancies that could lead to potential disputes. NGNTS would also be subject to some form of investment decision input criteria to help justify their investment decisions.

Conclusion

9.17. For the reasons set out above, we do not support Ofgem's proposals to introduce the gas entry auction based allocation as the enduring NTS exit arrangements. In particular, we do not believe that they are compatible with the physical characteristics of the exit arrangements. Nor do we believe that it is appropriate for regulated monopolies to compete with commercial organisations for capacity. Furthermore, the transfer of risk from the NTS to TCCs and GDNOs is not proportional or justified and could have a detrimental impact on security of supply, competition and customers.

9.18. We have therefore sought to clarify the issues and objectives that we believe Ofgem is seeking to address through its proposals for exit reform and have developed an alternative proposal. We believe that our alternative proposal that is based upon an efficient and previously proven approach involving the exchange of information by all parties, that is enhanced by regulatory input and output incentives is viable. In particular, it provides NGNTS with enhanced information that would enable it to make efficient investment signals. It would also provide a mechanism for the GDNOs to ensure that efficient decisions are made in respect of how best to meet its capacity requirements. We also believe that it allocates risk appropriately between the various parties. Finally, it is demonstrably more simple and transparent than the auction regime.

10. Financial Issues

Financeability

10.1. Ofgem has an obligation to ensure that the licensees are able to finance their activities. In practice, this means that a cost of capital has to be set at a level sufficient for the licensee to attract equity finance. The licensees are also required to maintain a good investment grade credit rating. Against this background, it is essential to ensure that the key financial ratios are comfortably within the limits required to maintain such a rating and to encourage equity to invest in network businesses.

10.2. We continue to believe that the traditional "building blocks" approach to setting price control is appropriate and is capable of remunerating the increasing capital expenditure requirements to cater for renewable generation. However, given the increasing importance of financeability, we believe that the key financial indicators should be agreed beforehand, together with the appropriate hurdles for each of these indicators. This will permit a more transparent process for assessing the financeability of each licensee and in Ofgem meeting its obligation to ensure that licensees are able to finance their activities.

10.3. In addition, there are clearly a number of options for addressing any financing issues. These include additional cash allowances (e.g. the adjustment to Seeboard's income in the distribution review), accelerating depreciation (e.g. the distribution review again and also the repex mechanism in gas) and increasing allowed returns to attract additional capital (e.g. as per the water sector). These alternatives need to be very carefully modelled and the options discussed early in the price control process.

10.4. The forthcoming paper on financing networks with Ofwat may represent an opportunity for Ofgem to raise these issues in more detail.

Cost of Capital

10.5. As noted above, investment in the transmission networks is likely to increase in the forthcoming price control period and it is therefore vitally important to set the cost of capital at a level that allows the licensees to finance these investments.

10.6. It is increasingly apparent that a number of utilities are competing for capital to fund large-scale infrastructure investments, for example renewable generation, railways and water all have large current capital programmes. It is therefore apparent that capital providers, including equity, have a large pool of possible investments. As a consequence, it is vital that the cost of capital set by Ofgem allows the transmission licensees to compete in the European capital markets.

10.7. Against this background, we firmly believe that efficient companies should be capable of earning more than 6% post-tax real. Assuming that there is scope for such companies to outperform the price control by 50-100 bps (which there is not at present), then a minimum cost of capital above 5% is inferred. In our view, a post-tax WACC in this range can be justified by an assessment of the requirements of equity investors.

10.8. We would in particular reject any suggestion that transmission asset ownership is presently significantly lower risk than electricity distribution and therefore deserves a lower cost of capital. On the contrary, given the scale of investment to accommodate new renewable generation it is clear that the capital requirements of transmission licensees (and particularly SHETL given its relative size) are substantial and indeed greater than in distribution. At the very least therefore the cost of capital for transmission should be no lower than the figure adopted in electricity distribution of 4.8% post-tax real. However, as noted above, even this in isolation is likely to be sufficient to attract the required equity and debt finance to fund new renewables infrastructure.

Taxation

10.9. The treatment of tax is an important consideration in the price control and in the recent distribution price control review there was a change to a post tax cost of capital.

10.10. We believe that the same approach to tax should be used in transmission as has been used in electricity distribution. It is particularly important for a licensee with both distribution and transmission licenses to ensure that there are no perverse incentives on investment in one rather than the other.

10.11. We therefore agree that a company specific, ex-ante approach to setting tax allowances is still relevant, to preserve incentives for tax efficiency. In setting such allowances, we do not consider it appropriate for Ofgem to claw back the tax benefits of interest payable on debt guaranteed by the licensee, since this will encourage a greater proportion of direct debt, increasing the risk profile of this business.

Gearing

10.12. In principle, there should be no major differences in efficient levels of gearing between distribution and transmission companies. Furthermore, we do not believe that there is compelling market evidence to move away from the previous 57.5% gearing assumption and that levels in excess of this would increase the risk profile of the transmission businesses. We therefore believe that the gearing assumptions used in determining the regulated revenue should be consistent with that in the distribution price control review.

RAV Roll-Forward

10.13. We agree with Ofgem's proposed approach for setting the RAV and, in particular, the application of the guidance set out in Ofgem's open letter in advance of the gas DN sales. This set out that any investment could be capable of inclusion in the RAV and retrospectively funded, but only if it could be proven to be necessary and efficiently incurred. We agree that this is the appropriate benchmark for rolling forward the RAV.

10.14. However, in the recent electricity distribution price control review, Ofgem did not finalise the DNOs' RAVs until very late in the process. We would therefore urge Ofgem to clarify the opening RAVs for 2007 early in the price control process, in the interests of eliminating as much uncertainty about the price control outcome as early as possible.

Depreciation

10.15. The cessation of the pre-vesting depreciation allowance towards the end of this price control period would, unless corrected, involve a "cliff edge" drop in regulated revenue without any corresponding drop in cash costs. The same issue emerged during the recent distribution price control review and adjustments were made to regulatory depreciation to deal with the problem.

10.16. We therefore believe that the cessation of pre-vesting regulatory depreciation in transmission should be dealt with in a similar way by adjustments to the regulatory deprecation period. This will smooth the transition and avoid a cliff edge of regulatory revenue reduction. It will also smooth the price impact of additional revenue to fund investment in infrastructure for new renewable generation.

Pensions Issues

10.17. We agree with Ofgem that the broad policy principles adopted at the last electricity distribution price control review should also apply in transmission. In particular, we agree that efficiently incurred pension costs, including deficit repair, are a normal cost of business and should be capable of being recovered. In this regard, the pension position of SHETL is due for an actuarial assessment in Spring of this year and the results of that assessment will need to be fed into Ofgem's final proposals for allowed revenue both in terms of deficit repair (should that be necessary and noting that the scheme is not currently in deficit), and increased employer contributions.

10.18. We agree that Ofgem's proposals in relation to pensions will need to take into account the allocation of pension costs between price controlled and non-price controlled activities. In terms of over and under provision of pension costs during the current price control period, unlike the gas price controls, no explicit allowance was made for pension costs. We therefore agree that since those allowances are not known with certainty it will be difficult to allow over or under recovery of previous contributions in electricity transmission. However, in terms of the gas price controls an explicit allowance was made, so it will be possible to return to each licensee, including the gas distribution networks any over or under provision.

10.19. We also agree that Ofgem's proposals will need to be consistent with the Pensions Act 2004. To the extent that the Act and the new regulator make changes that increase pension costs, these will need to be taken into account. It is not known yet whether this will be the case (for example, in relation to the allowed timescale for deficit repair). Nevertheless, if a similar mechanism for pension cost recovery is adopted as for electricity distribution in relation to "truing-up" of amounts spent in 2007-2012 at the 2012 price review, that uncertainty will be addressed.

10.20. Finally, the Pension Act 2004 does create a new liability to contribute to the Pension Protection Fund (PPF). These costs are normal commercial liabilities and should therefore be treated in the same was as the generality of pension costs.

Reporting Requirements

10.21. As noted previously, while we are supportive of the proposed regulatory reporting pack for transmission, we would urge Ofgem to be proportionate in terms of its application to transmission.