Transmission Price Control Review – Initial Proposals
Response by Association of Electricity Producers

24 July 2006

Introduction The Association welcomes the opportunity to comment on Ofgem's initial proposals for the 2007 Price Control Review. The Association of Electricity Producers (AEP) is the UK trade association representing electricity generators. It has some 90 members ranging from small firms to large, well-known PLCs. Between them they represent at least 90 per cent of the transmission connected generating capacity and they embrace nearly every generating technology used in the UK. Many member companies have interests in the production and development of renewable energy where the government has set ambitious targets for development over the next decades.

Our response to the consultation document falls into two parts: general comments and then detailed comments that follow the layout of the questions posed within the document. The question is posed in italics and our response in normal font.

GENERAL COMMENTS

Context of the Review: This review takes place at a time of unparalleled change in the regulatory and policy environment within which it is placed. From the perspective of generators and developers the TPCR is important, but is by no means the only important work area. The need to ensure joined-up thinking between the TPCR and related areas such as OTEG, EU-ETS, and the outcome of the Energy Review is paramount.

Engagement: This review has been characterised by involvement of stakeholders and meaningful consultation by Ofgem. The Association welcomes this openness and inclusive approach.

Types of Outcome: The turbulent environment within which this review takes place and the challenges facing generators lead to the following general observations about the outcome of the review:

- The turbulence is likely to mean that neither Ofgem nor the network providers will be able to be perfect in all their decisions. Nevertheless, there is an asymmetric risk here: having insufficient network poses a greater risk to security of supply than having a surfeit of network;
- Another consequence of the current regulatory and policy environment is that generators will seek outcomes from the review that are simple and stable over time. Although the financial duration of the review is 5 years (some of the incentives proposed could go to 10 years), generators will look to have a basic pricing framework that is stable for 10-15 years.
- Considering the above the Association has a preference for simple stable outcomes and an expectation that any further interventions by Ofgem will

be demonstrably and substantially cost-beneficial, for them even to be considered; regulatory risk is a major factor in further industry development.

DETAILED COMMENTS

Chapter 6: National Grid Gas (NGG NTS)

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

The document does not provide sufficient information for us to comment on this in an informed way. However it may be that the decision to invest at St Fergus was taken in the early days of the long term auctions, indeed this must be the case if the investment has already been delivered given the usual three year lead time. At this time is was our understanding that that the usual planning approaches would operate alongside investment signals from long-term capacity auctions, therefore it may be the case that in the absence of an auction signal that NG decided that investment was necessary to meet its 1-in-20 obligation. In such circumstances it would not be appropriate to disallow this capex.

Chapter 7: Price control assessment and general policy issues

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

Reluctantly we are driven to the possibility that some unspecified events may not be forecastable and yet have profound impact on the economics of new and existing plant. By definition these would be events not in the current spectrum of likely events and hence difficult to specify ahead. Nevertheless, possible contenders would be wide scale changes in the economics of differing technologies arising from events such as:

- the possible banding of renewable technologies
- a profoundly different approach to EU-ETS Phases II and III from that which is currently anticipated
- a radically different outcome from the work of the OTEG project than is currently anticipated.

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

In Section 7.31-7.34 Ofgem recognises the turbulence of the policy and regulatory environment and there are a number of proposals in the draft TPCR that seek to address this:

- The proposals for revenue drivers to vary revenue allowances automatically with load related expenditure sounds like a good principle and we await the detail.
- It also sounds about right that incentives should be shallower rather than deeper, given the investment environment we are in.
- Again it seems reasonable to suggest that local and infrastructural investment expenditure will need differing approaches (10.5-10.10)
- Also a rolling incentive period will encourage the licensees to schedule expenditure at the right time, rather than front-loading.

Other Issues:
From a generator's perspective there are a number of other areas where we want to see parallel progress, if the benefits promised by the TPCR are to be realised. For example:

- The Access Reform Options Development Group has produced useful output in a number of areas, including alternative options for access products. We hope this process will continue to move in parallel with the TPCR
- We also know NG are about to bring forward proposals to mitigate the financial risk arising from the clustering of connection projects and to limit the commercial exposure of potential connectees in the early stages of development. These proposals are all about allocation of risk and are potentially useful, provided Ofgem step up and play their part in developing these proposals. We hope this is factored into the TPCR.
- The Offshore Transmission project chaired by Ofgem and DTI is likely to produce material changes to the arrangements for connecting offshore generation. This will directly impact onshore investment, charging and market operation. Again generators want to see joined-up thinking between government and Ofgem.
- Finally, the Association is very concerned about the planning process and its impact on generation projects. The same is equally true for transmission and other network projects. We hope that government and regulatory bodies will take the opportunity of the TPCR (and the Energy Review outcome) to improve and to streamline the planning process.

Chapter 8: Financial issues

The Association makes no specific comments in this section.

Chapter 10: Adjustment mechanisms and incentives: electricity

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

The Association looks forward to the detail of this driver, but our initial response is a cautious welcome.

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

The opportunities and pressure for innovation will increase over this control period. Some support for innovation will help this. However, it does place a burden on Ofgem to ensure such proposals do not become an exercise in 'using up' an allocated budget, but rather can be shown to reasonably promise to deliver benefit in the medium term.

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

The normal structure of the price control allows licensees to benefit from innovation. Together with the proposal for rolling incentive periods, this should also encourage licensees to innovate.

Other issues:
Informational Asymmetry: The split of the SO/TO functions introduces further scope for asymmetry of information between the regulator and the monopoly providers. This is another factor that emphasizes the requirement for simple transparent regulation so that market participants can have confidence in the performance of the regulator and the network providers.

SO Incentive Scheme: There is currently no SO Incentive scheme and yet NGET is running the transmission system using the same processes and criteria as last year. Before any new scheme is proposed we believe the time is now right to consider more market-based approaches to response and reserve. In this case such sharing factors as might exist would need only to be shallow.

System Reliability Incentive: Finally, we are glad to see that the blackouts in London and Birmingham are now sufficiently distant in time that the ill-conceived system reliability target is likely to transform into a minimum standard of performance with a possible penalty for shortfall.

Chapter 11: Adjustment mechanisms and incentives: gas

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

We welcome this revised approach that will require entry capacity release up to defined baselines and we acknowledge that Ofgem has responded to industry concerns in this regard. We support the principles of enabling re-allocation of unsold baseline capacity to nearby points as this should provide for efficient allocation of existing capacity and ensure that investment only takes place where necessary. Clearly there is much work to be done in establishing the methodology and transparency of process and the outcome will be important to provide confidence to industry participants.

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

Whilst we are not in a position to comment on the absolute levels of the revenue drivers the approach to set these for specific incremental bands seems reasonable. However there will be risks to NG where actual costs diverge from the revenue drivers and this could create some perverse incentives.

We also support proposals to continue to make available baseline capacity at the day ahead and within day stage. We agree that is will be necessary for the principles of the discretionary release of interruptible capacity and its pricing to be more fully understood. This is important to ensure that all capacity is made available to participants.

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

We consider that a clear case for an innovation incentive has not been made

Chapter 12: Environmental considerations

The Association has no specific comments on environmental considerations.

Appendix 16: Offtake revenue drivers and baselines for NGG NTS
A16.1 Do you agree with our initial proposals for the transitional period with respect to:
a) Baseline levels?

We broadly support this approach

b) Revenue drivers?

We support the approach to provide for Authority oversight of planned investment which is not supported by an ARCA. We are not in a position to comment on whether the values derived for the revenue drivers are appropriate.

c) NGG NTS incentives

Consistent with our views outlined in our response to the March document, we consider

- charges foregone and exit investment incentive should not form part of the next price control
- CLNG incentive should be retained but the level of the target will need to be informed by the need to constrain LNG once new supply sources come on stream and reinforcement for Langage power station has been completed. We therefore do not support the £2.1M target as it is based on no information and simply assumes the requirements for CLNG will continue at the 08/09 level.

- Buy back and greater than 15 day interruption incentive - we agree with these proposals

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

The baselines ensure that existing firm access users have at least their current capacity available going forward, but also provide baseline values up to or beyond SOQ for current interruptible sites. We have been advised that this excess capacity above firm levels has derived from entry related investment. Clearly current interruptible sites have never signalled a need for such capacity yet they are to be allocated a baseline with commercial arrangements that strongly encourage them to secure this on a long term basis. In the context of customer choice and a user commitment model this is all rather odd! It's as though past efficiencies through having interruptible sites on the network have been wiped out by entry investment and we are about to start again with a universal firm regime. It is really hard to understand how, in the longer term, this is going to deliver efficiency and security of energy supply, even though new exit investment may be allowed to be interruptible. This regime will change the economics of maintaining or installing alternative fuel capabilities on generating and industrial plant which could have security of supply implications. Similarly the absence of interruptible terms will reduce the tools available to NG for managing system constraints, here we recall the summer interruptions of 2003 and more recently the events in early July associated with maintenance at Teesside. In addition system emergencies may become more likely as the significant interruptible volumes will be moved from stage 1 to stage 3 of an emergency.

The proposals to provide baselines for the interruptible offtakes in the south-west quadrant only exacerbate these issues as this is above the practical maximum physical level, yet no details are provided on the associated buy-back incentive for NG in connection with these offtakes. Clearly the drive to provide universal firm access rights for all offtakes is driven by the desire to treat all offtakes equally to ensure non-discrimination. However it is not clear that this is necessary or desirable particularly in this case.

We can envisage a scenario where a currently interruptible CCGT has been allocated its full capacity requirements as a baseline and it decides to go firm given the administrative burden and risk of relying on a discretionary release of daily interruptible capacity. This site may decommission any back-up fuel capability. In a few years time a new CCGT wishes to connect nearby. Under the current arrangements the 'spare ' network capacity could have been allocated to this offtake, and NG would have been breaching its licence if it had invested for this plant as it would not have been efficient to do so. However under the new arrangements NG may seek offers for interruption in the local area but these may not be forthcoming given past decisions. The point being that the reforms may well drive decisions which may not otherwise have been made. All this means that NG will have to invest to meet the firm capacity requirements of the new plant, leading to more investment rather than less!!!

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

We consider that the substitution obligation should enable NG to re-allocate uncommitted capacity to nearby offtakes. Clearly transparency will be a key issue in establishing industry confidence in this process. We would also like to note that this feature is only necessary because individual nodal baselines are a feature of the enduring arrangements. In the current arrangements NG acting in accordance with its licence conditions should consider spare capacity in the locality before making incremental investment and a failure to do so would place it in breach of its licence. So these new arrangements are unlikely to change NG behaviour but may provide for increased transparency to participants and Ofgem in undertaking its market monitoring role.

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

The Association is not in a position to calculate whether these revenue drivers are set at the appropriate level or not. We find the 80% factor applied to the revenue drivers for Pembroke and Grain rather curious. This clearly creates an incentive on NG to seek contractual solutions for the provision of capacity at these offtake. We can only assume that in some way NG would like to link offtake capacity provision to import flows at these facilities. However it is unclear to us as to the incentives on these project developers to agree such terms when these parties may not have a direct relationship with parties importing gas at these terminals and therefore no influence over import flows. They may therefore be unwilling to negotiate such terms as they may then be exposed to the uncertainty in the global LNG market, maintenance at the LNG plant, missed delivery slots, problems with tankers etc….

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

We support the proposal to increase offtake baselines when additional capacity is created by entry related investment or vice versa. This should provide for transparency of information on capacity availability. However this may also be achieved when the EU gas regulation on access to networks is fully implemented since this requires publication of information on firm, booked and available capacity at relevant points on the network. These numbers may in practice diverge from the baseline values if they exhibit seasonal variations and this will need to be understood by participants.

A16.6 Do you agree with our proposals with respect to buy backs of offtake capacity?

We broadly agree with the proposal in respect of investment related buybacks of capacity, with NG being fully exposed to these costs, albeit perhaps with some flexibility over the investment lead-times on application to the Authority. However we would like to reiterate our concerns (as detailed in our response to the March document) regarding the alignment of investment lead-times for

NG and CCGT project developers whilst there is alignment of timescales for capex commitment. If the commercial regime does not reflect these decision points then inefficient outcomes are likely as NG may deliver incremental capacity that has been signalled but a later decision has decided to abandon or delay investment in plant. We understand that under the proposed enduring arrangements the developer would be liable for a number of years, yet to be determined, for exit capacity charges but that may not prevent this situation from arising.

The setting of an administered price for investment related buy-backs above the cost of the capacity is a step forward in respect of providing compensation for late delivery of capacity and in increasing incentives on NG to deliver capacity according to contracted timescales. We note that this value of 0.52p/kWh has been derived from entry related buy-backs only, as there is no similar process for buying back offtake capacity. Whilst it may be pragmatic to set these at the same level, further consideration should be given as to whether this is appropriate and adequately protects consumer interests. Late delivery of infrastructure at entry will prevent gas entering the system at that entry point but may allow contractual commitments to be met by securing gas at other entry points or the NBP. On the other hand late delivery of exit capacity serving a specific consumer (generator, industrial site) or storage facility may prevent that site from offtaking gas at all, with potentially more severe financial consequences. Clearly if the connection has been made and it is the reinforcement work that is delayed then this situation may be offset to some extent if interruptible capacity can be made available. To summarise, the application of the administered buyback price may not be appropriate in all circumstances, where for example the LNG plant, CCGT, industrial plant or storage facility has also experienced delays or has been deferred. Further consideration needs to be given to these scenarios to ensure these are adequately reflected in the commercial framework and to avoid unduly penalising NG.

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

We broadly agree with these proposals and consider it is important that all available capacity is made available to participants. We are unclear on the potential interaction day ahead and within day of unsold baseline, non-obligated capacity and discretionary interruptible release. So, for example, could discretionary interruptible be withheld day ahead in case unsold baseline is requested within day? Further clarity is required on these interactions before we are able to comment on the incentive structure.

Appendix 17: Draft enduring offtake impact assessment

A17.1: What are your views on the benefits analysis conducted?

We think the benefits case is a gross overestimate of the benefits that may arise from the introduction of the enduring arrangements. It seems to imply that the current arrangements will lead to substantial inefficiencies and that

NG will discriminate between offtakes in the absence of any reforms when this would clearly be a breach of its licence condition in a number of areas. Therefore, if NG's behaviour does not change, the main benefit of reform will be improved transparency allowing Ofgem to undertake its market monitoring role more effectively than it current now.

Table 17.3 details forecast incremental NTS exit capacity capex with an anticipation of, on average, a spend of £65M. This references Chapter 11, but this chapter does not consider capex. Chapter 6 discusses capex but there appears to be no consistency with the numbers in table 6.3 nor with those relating to exit capacity investment detailed in the 2005 Ten Year Statement. Further detail of the assumptions supporting this forecast would be appreciated.

We acknowledge that there is likely to be substantial investment in CCGT plant in the coming years to help meet the expected generation gap, however, the Energy Review does not seem to assume that investment will be solely in gas fired plant. We therefore wonder whether assuming £65 M pa. for the next twenty years is appropriate, particularly when other issues such as energy efficiency initiatives and the effects of climate change act to suppress distribution network load growth. Indeed it has already been stated that no exit load related investment is expected in the next price control period except perhaps in the south west quadrant to meet any load growth. It therefore follows that any investment made will be for specific large projects which currently would be covered by an ARCA effectively providing a clear investment signal and financial commitment. Under the enduring arrangements effectively standardised ARCA type terms will be established, so there is little change. Any benefit will only accrue if NG behaves differently and effectively puts less pipe in the ground to deliver the same capacity. Given the fact that pipes are only available in certain size increments this is difficult to envisage. We therefore query the appropriateness of the 6.5% capex saving as this is difficult to appreciate on an individual project basis. Putting the same pipe in the ground more cheaply should be considered separately from these reforms which are clearly aimed at maximising the utilisation of the existing system with benefits accruing from making less investment. Clearly simply using a % saving because it has been used before does not mean this is the correct measure.

It is not clear how the savings arising from the removal of the flow margin are considered in the impact assessment. If this change is accepted then clearly there will be less investment as load growth initially uses this margin before requiring investment. Also it is not obvious why this is linked to these reforms nor if it is actually desirable. Whilst adding a 5% margin onto the 1 in 20 forecast may seem like a 'belt and braces' approach the risks of inadequate capacity far outweigh the costs to customers of investment to provide this safety margin. In terms of security of supply a little overcapacity may not be such a bad thing and may well provide resilience to a wider range of supply / demand scenarios.

We accept that in the absence of change there may well be more ARCAs than there have been in recent years, particularly in connection with new CCGT investment. We also agree that it is desirable to reduce the number of determinations, given the cost burden this creates on all parties. However it is not obvious that an increased incidence of ARCAs would necessarily lead to more determinations as each determination effectively sets 'case law' for future connections, so long as Ofgem does not keep moving the goalposts. We consider the current case concerning the proposed CCGT at Marchwood has only been referred to Ofgem because Ofgem indicated to NG that the terms of the Langage ARCA were no longer considered appropriate. As Ofgem can therefore influence which determinations occur is does not seem appropriate to consider this as a benefit of reform.

Non–discriminatory allocation of capacity products is another area in which benefits have been quantified; however these are based on the presumption that in the absence of the reforms NG would discriminate between offtakes. As NG would be in serious breach of its licence we would not expect NG to behave in this way given the risks of this being discovered. We accept that the proposals provide for greater transparency of information that would enable any such behaviour to be more easily revealed, however greater transparency under the existing arrangements may similarly achieve such ends.

With respect to benefits that may accrue in the electricity market, we simply do not accept that this will be the case. Whilst the flexibility arrangements are still under development it seems likely that the cost of CCGTs securing flexibility (even if only on constrained days) will be higher than it is now. In addition they may also face overrun charges in certain circumstances; therefore the cost and risk of offering flexibility to the electricity balancing mechanism will at best stay the same or increase.

To summarise, the benefits case seems to be based on the avoidance of certain behaviours by NG that would place it in breach of its licence and it seems highly unlikely that such behaviour would occur. We are therefore extremely sceptical that the quantified benefits will be achieved and will manifest themselves in reduced costs to customers.

A17.2: What are your views on the cost analysis conducted?

We find it quite remarkable that Ofgem has eliminated outliers from their analysis given that this is only a draft impact assessment. This is a particular concern given the different levels of understanding of the proposals and engagement of participants in the process. Given the small sample sizes such elimination is unlikely to be statistically defensible.

Clearly the cost estimates will have to be reworked when and if we have greater clarity over the flexibility arrangements. We hope that due consideration will be given to OPN based models in future documents as these provide continuity of existing well established operational procedures.