Transmission Price Control Review – Third Consultation
Response by Association of Electricity Producers

28 April 2006

Introduction The Association welcomes the opportunity to contribute to the development of the 2007 Price Control Review and applauds Ofgem's early and ongoing involvement of the industry. 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 follows the layout of the questions posed within the document. The question is posed in italics and our response in normal font.

Chapter 2: Form and structure of the price control

General Comment This Price Review deals with a substantial amount of investment in networks and a change in the balance of technologies being connected to the network. Therefore the onus on the Regulator to make robust and long-lasting proposals is greater than before. For the same reasons the risk of less than perfect decisions is greater. In these circumstances it would be prudent for the Regulator to consider and set out how it will manage the 'course corrections' that may be needed over the next 5 years and beyond. What would be acceptable points to intervene and what would be just tinkering that would enhance regulatory risk?

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

The basic RPI-X structure has proved to be reasonably robust during 15 years of unparalleled investment in the transmission system, therefore we would suggest that its resilience is proven. However, in view of the substantial amount of investment indicated, together with the policy uncertainties facing generator/developers it is appropriate that an augmented RPI-X framework is considered.

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

In principle such types of incentives should be applicable to transmission networks. If rolling incentive mechanisms are introduced, we would suggest that a single period, say 5 years, should be used. Given the multi-layered corporate structure of SO/TO we would suggest that the default should always be the simple overall mechanism for periods of retention of benefit. Any deviation from this would have to be well-supported by assessment. It remains to be seen whether the double layering of agent/principle between Ofgem/SO/TO will allow efficient assessment of investment.

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

This may be the correct way to develop incentives. However, the interaction between a developer and NG is always asymmetric and such a mechanism needs to bear in mind the degree to which NG will fix an income target and then drive its negotiations with developers to achieve this target. Such an outcome would not be in the wider interest of the consumer as it might lead to sub-optimal cost-bases for generators.

Also, given that Ofgem acknowledges the informational asymmetry issue exists, setting of more challenging targets suffers from the same problem that the regulator cannot know the 'correct' baseline. This would therefore suggest that any additional incentive for 'challenging targets' should be progressive as it moves away from the comfort zone. However, such an approach will carry the other burden of complexity of administration.

Revenue drivers based on the quantity of generation connected need to be derived with an eye to the locational factors that affect or determine any generation siting. It should not, of itself, provide NG with an incentive to coerce generation to locate at sub-optimal sites.

We concur with the proposal that the base control period is 5 years, subject to the rolling incentive approach. We also believe that the basic structure of the price control should be designed so that its structure is intended to be robust for 10-15 years, although the specific parameter values may change.

<u>Differential Rates of Return:</u> The rate of return is an average across the asset base. This is a useful simplification. Where NG can propose investments that are substantially cheaper than the current average, the average rate will provide a useful benchmark. We are sure that if the converse is always true for new assets NG will make this plain.

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

We look forward to the results of the further discussions between NG and Ofgem in exploring this option that are pointed to in the consultation document.

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

We await the outcome of the current impasse with interest. We understand that one option available is to rely on the relevant licence condition. If that is the course taken, Ofgem will be in a better position to assess the benefit available from re-introduction of a scheme.

The next year will give an indication of how stable the balancing regime is likely to be post BETTA go-live. From this we should be able to draw some conclusions about the scope for longer term SO Incentive Schemes. Much hinges on the outcome of the Energy Review. Overall, however we would prefer development of the SO Incentive mechanism towards more market-based approaches to response and reserve. Stability of the structure of any residual incentive scheme would help parties to predict possible levels of BSUoS and hence factor them into their cost base. The financial values in the scheme would be expected to vary year-on-year. In any residual scheme, we would not favour large sharing factors as this tends to drive more volatile costs. Finally, we would not support any slackening of the controls on income adjusting events; if anything the criteria for acceptance should be tightened. Otherwise, this introduces an event risk that would reinsert volatility into the costs.

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

Equalisation would appear to be a prudent approach in order to ensure that incentives for gaming are minimised. We would suggest that the less generous of the two existing approaches should probably be preferred.

Chapter 3: Electricity incentives

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

In principle this approach may have merit. However, as is often the case with electricity the devil is in the detail. It is not clear if a locational approach would lead to NG encouraging/coercing generators into particular zones or locations. Also, does the magnitude of change envisaged mean that the current zonal boundaries may become untenable? We look forward to initial proposals in June. Noting Ofgem's warning that revenue drivers might need to be supplemented with other mechanisms, we are concerned that the edifice of incentivisation may become too complex with the attendant risks of perverse incentives and/or gaming opportunities.

Para 3.20 raises the concern that NG may not provide connections 'as quickly as practicable'. Surely, if they are not provided as quickly as possible, then NG is not in compliance with its licence condition and Ofgem should act?

Para 3.30 It should be noted that in a cluster Final Sums Liability will only finally fall away when last generator in the cluster is connected. This may be some time after the first has begun operation. This protracted contingent liability is one of the problems with the cluster approach.

There appears to be an assumption within the section on connection that planning risk can be easily managed by NG. Experience shows this is not the case. Provision of hard financial commitments does not solve the planning issue. A situation in which a generator is connected but cannot export because planning processes have led to a delay in network infrastructure build is not solved by financial penalties, merely mitigated somewhat. Ofgem should perhaps consider a far more active role in supporting the rapid achievement of planning permits for infrastructure that is supported as a result of the price control. This would prevent the problem arising in the first case.

Para 3.35: The Association opposed the system reliability incentives when introduced on the grounds that:

- NG's performance to date was demonstrably better than most (if not all) other developed economies
- No indication was given as to what different activity the incentive would initiate and therefore how it would incentivise; &
- Any incentive for better system availability would be better placed on distribution network operators.

As a consequence, we believed that the incentive was no more than a bet between Ofgem and NG on an outcome that neither could effectively influence. Going forwards, this incentive has been extended to the Scottish TOs and, in so doing, been made even less related to the delivery of energy. For the future, if this incentive is retained in a penalty only version, a meaningful standard is defined and placed as a licence condition, akin to the maintenance of frequency within prescribed limits.

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

We would suggest that Ofgem should ensure that only the minimum efficient Capex to integrate baseline generation and demand changes is allowed and that the baseline is itself sensible and not skewed. Then they should ensure that changes from the baseline should trigger the minimum efficient additional Capex allowance or full Capex claw back as appropriate.

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

Yes, but tough negotiation will be necessary to ensure that the TOs do not consider deliberate overspending as a risk-free strategy.

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

The current Energy Review should lead to robust policy frameworks that will last well beyond the next 5 years. International development of emissions policy frameworks and trading arrangements should be occurring during the next 5 years and have the potential to shift the baseline. Insofar as they change the commercial balance between generation technologies this will impact the needs for network investment and may require review of the investment base case. In this event it is important that any intervention by the regulator is well signalled, of short duration, carried out against clear objectives and transparent.

Nevertheless, the goal should clearly be that a well-designed set of drivers should obviate the necessity for re-openers under all reasonably foreseeable outcomes.

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

Exploration of access arrangements is a part of the range of issues that need to be addressed. It is entirely conceivable that new access products will be viable and attractive to users. The ARODG group has provided a useful forum for testing some of these ideas in a preliminary way. However, the Association remains concerned at the 'user commitment' approach to access that has been discussed with Ofgem on a number of occasions recently.

Chapter 4: Gas Entry Incentives

The Association is concerned that Ofgem is proposing to make quite such a fundamental change to the regime when it has only been running for a few years. There has been little thought as to the messages this sends to those making long term commitments in relation to the increased risk that arises from regulatory uncertainty. This is not to say that known deficiencies in the regime should not be addressed, but that, by doing so, parties may be less willing than previously to make long term commitments as the regime may change again at the next price control review.

The Association supports in principle the changes to the way in which NG is obliged to offer capacity to the market as this should support the efficient allocation of existing capacity. The challenge will be ensuring that the detailed implementation of this high level concept works as intended and provides a sufficient degree of transparency to provide participants with confidence that the outcome is desirable and efficient. Clearly there are many details to be addressed not least the publication of a network model that must be sufficiently user friendly to be of value to participants. Ofgem must satisfy

itself that this is capable of implementation in an acceptable manner in the timescale required.

We consider that the approach to revenue drivers may have merits but that there could be undesirable effects if the actual costs diverge from the allowed revenue derived from the revenue driver. This could be particularly significant if the costs are high as this may create an incentive to delay delivery of incremental capacity especially at existing entry points where the buybacks may only become necessary at peak. In such circumstances it may be more difficult to distinguish between operational buybacks and investment related buybacks, which could be important for operation of the proposed buyback arrangements.

In principle we agree that investment related buybacks can be treated differently to operational buybacks but these must be distinguishable in all circumstances. We consider that the buyback cost should reflect the circumstances where NG is accountable for any delay and not simply refund capacity charges; however this could leave NG facing unlimited charges and may not be acceptable.

Chapter 5: Gas offtake Incentives

Please see comments against the questions in Appendix 12

Appendix 12: Gas offtake technical details
The Transitional Regime

Qn A12.1
We note from the text A12 1.17 that it is envisaged that baselines through to October 2010 will perform a single function as a high level delineation between TO funding and remuneration of incremental investment, so that NG is not remunerated for providing capacity on a firm basis that already exists within the network and for which it does not need to make any investment. Therefore setting baselines on a practical maximum physical basis which is consistent with the underlying network capabilities is appropriate. In addition setting baselines on a nodal basis is consistent with the capacity product and will provide the clearest information to connectees.

With respect to interruptible capacity; by its very nature no investment is required to provide it. Therefore we agree it is not necessary to provide baselines for interruptible capacity. We are unclear as to the role of such baselines in the current price control, although we note that this is different from not setting baselines for interruptible offtakes or offering interruptible services.

With respect to the setting of baselines for GDN flexibility we agree that these do not need to be set for the transition period but not with the reasoning behind this. Rather we consider that since investment is unlikely to be required to provide additional flexibility for GDNs this is a pragmatic step that will avoid undue complexity in the price control. In principle, if the same logic

as above is applied to flexibility, with NG only being remunerated where incremental investment is required, baselines should be set for flexibility so that GDNs are aware of the flexibility that is available without investment being necessary; the fact that TCCs have different arrangements is not strictly relevant.

QnA12.2
We agree that in principle the use of revenue drivers through the whole price control period would appear to be appropriate and acknowledge that this might require Ofgem oversight of investment where there is no specific user commitment. We also wonder if a similar mechanism might be required in the enduring regime when no incremental capacity is required but where investment is required to maintain existing levels of exit capacity due to changing flows at entry?

However we have some concerns over the setting of revenue drivers and, if these diverge from actual costs over time, this could lead to the creation of perverse incentives to delay delivery of capacity if actual costs were above the allowance.

Qn A12.3
We consider that the charges foregone and exit investment incentive should not be part of the next price control as their role and usefulness is limited given the reduced cap introduced in 2004. They will also, to some extent, become redundant if practical maximum physical baselines are set with revenue drivers to remunerate investment.

Qn12.4 &5
Given NG's continued ownership of constrained LNG facilities we consider that it is appropriate to continue with this incentive in the transition period and that it should also continue in the enduring period. As regards the appropriate target level, consideration should be given to the anticipated requirement for LNG facilities to be constrained; as no information is provided on this it is difficult to comment further.

QnA12.6
As capacity is largely unconstrained in the transitional period and NG have some rights to defer the delivery date for incremental capacity in ARCAs and continue to be able to call maintenance days we agree that all buybacks should be excluded with respect to the buyback incentive. NG will therefore bear the full costs of buybacks that relate to its own actions.

Qn A12.7 & 8
We agree that in principle the 15 day incentive should be retained to minimise interruption of NTS sites. However given the experience in recent years and the fact that practical maximum physical baselines reveal that very little interruption is required, it seems this incentive serves a limited purpose and NG may achieve or exceed any target easily such that it maximises its incentive revenue by very little, if any, effort and this simply creates an additional cost to customers.

The Enduring Regime

Qn A12.10

The Association agrees that user commitment models may reduce the risk of stranded assets emerging on the network, however we remain to be convinced that this is a major issue. Neither NG nor Ofgem have as yet been able to present any information on the extent of stranded assets that exist on the network. We also do not seem to have an agreed definition of what constitutes a stranded asset; is it an asset that has been built and never used, used at a lower capacity than expected or not used until a later date than originally expected?

We consider that there are a range of models that may fall under the heading of user commitment and there are many variations of these models depending on the numbers selected for various parameters. The extent to which any user commitment model may deliver more efficient investment signals and potentially reduce stranded assets will depend on the compatibility of investment timescales between NG, a distribution network operator, power station developer or storage operator. Where NG requires say four years lead time for incremental capacity and yet a CCGT can be built in two and a half years there is clearly a mismatch of timescales. This mismatch may lead to CCGT developers signalling and committing to capacity they are unsure that they will need or when they will require it. In practice the cost of developing an option to develop a CCGT at a particular point on the system will rise but this may not prevent companies developing such options. We consider that the actual build time for CCGTs and for laying pipelines may not be that dissimilar such that the profile of expenditure is also similar and heavily weighted to the two years prior to first gas. Therefore it would seem logical for the contractual framework to reflect this in some way with a mechanism for signalling capacity with sufficient lead-time for NG to undertake preliminary work but with a review point prior to significant expenditure on both sides to ensure that only assets that will actually be utilised are built. This is most likely to lead to an efficient outcome for both parties and consumers in general. We expect that other NTS connectees face similar issues.

Furthermore consideration should also be given to delivery dates other than 1 October in the first year to align delivery of capacity with the customer's needs, facilitate commissioning in advance of the winter period and manage other commissioning issues in a pragmatic way. It would clearly be inefficient to have to buy capacity from October 2010 when it is not required until September 2011!

We do not agree with the 2.5 year lead-time for reductions in capacity levels. It is not apparent how often this extended notice might lead to investment being avoided and we consider this a low probability event. Any extension of the commitment beyond current timescales will introduce additional complexity and liabilities to supply contracts that it would seem difficult to justify. We are also unsure as to why the sustained demand test requires a four year commitment rather than three years which was a feature of the

TANIF discussions. Five years has also been flagged as a possibility in the cost survey assumptions document. All of these values are arbitrary but none have yet been justified.

QnA12.11
The Association broadly agrees with the assessment of the options presented in the second consultation. In particular we agree that defining products or baselines on a zonal or global basis will lead to additional complexity, lack of transparency and may not provide locational specific investment signals to support efficient investments consistent with ensuring securing of supply. We consider that nodal products and nodal baselines are more consistent with the provision of locational specific investment signals, will be less complex for shippers and consumers, and therefore have lower implementation and ongoing costs than zonal models which could create significant uncertainty for system users. However we remain to be convinced that all offtakes must be treated exactly the same and have the same products. The physical characteristics and commercial imperatives vary significantly between the various offtake types and to fail to take this into account in the products offered may lead to inefficient outcomes that are yet to become apparent.

We acknowledge that some kind of substitution arrangements may well be appropriate and that an obligation with appropriate transparency may be better suited to the purpose than an incentive. We also consider that more thought needs to be given to exactly how NG will be obliged to offer for sale nodal baseline quantities, including which products over which timescales, to ensure that all capacity is made available to users.

QnA12.12
We agree that to link remuneration for load related incremental investment where there is a user commitment seems appropriate, but this is clearly linked to other issues including the baseline definition and interpretation of the 1 in 20 obligation. If either of these were to change from the view in this document then this linkage would also need to be reconsidered.

QnA12.13
We consider this proposed change in the interpretation of the 1 in 20 obligation is quite significant and we are surprised that Ofgem considers that it is not necessary to modify SSC A9 to make this quite clear. As with many of these issues we consider there are interactions with other issues. As such this interpretation may be reasonable and robust under a prevailing rights model but would not be under a finite rights model, since in the latter parties may have diverse strategies for securing capacity over different timescales.

QnA12.14
The Association's initial view is that capacity should actually be delivered before NG is remunerated for it, but we are not clear as to how investment will be financed. We are concerned that there may be a cost impact of this. We can also envisage scenarios when a more efficient outcome might be achieved if NG were to tender for long term buyback or prevailing rights surrender (including baseline) or interruptible contracts at offtakes close to

that requiring incremental capacity prior to committing to undertake incremental investment.

We note that this could lead to a cycling effect on the availability of interruptible capacity as these current reforms would essentially ‘force’ current interruptibles to go firm but new connections or sites close to them may be offered interruptible terms, potentially creating a new generation of interruptible offtakes at least until the next set of reforms!

QnA12.15
The Association agrees that setting the baselines on a practical maximum physical basis is consistent with the network capabilities and appropriate in the context of the other aspects of the proposals.

QnA12.16
The Association’s view is that static baselines are appropriate given the desire for all incremental investment to be supported by a user commitment. Static baselines are entirely appropriate for offtakes serving CCGTs, since any incremental requirements will be sizable rather than marginal. Also as DNs have 1 in 20 obligations then it would seem odd to ‘second guess’ DN requirements and build in a rising baseline for DN offtakes.

QnA12.17 & 20
The Association agrees that the revenue drivers approach has merits and is potentially an appropriate way of remunerating incremental investment, and that if the remuneration is linked to the delivery of the capacity that a separate exit investment incentive should not be required. This assumes that the revenue drivers can be set in such a way as to encourage delivery of capacity consistent with the timeline of the connectee. Where actual costs diverge from the revenue driver perverse incentives to deliver early / late may be created.

QnA12.18
Subject to the above we agree that setting zonal revenue drivers for small increments across a subset of offtakes in a similar geographical location is sensible. Also that setting project specific revenue drivers for individual large projects is that are anticipated at the time the price control is agreed is logical.

We accept that revenue drivers cannot be set for projects which are not anticipated at the time the price control is set and that these will require a licence modification. However we suggest that the process and timeline by which a developer requests this is made clear along with any interactions with other stages of securing offtake rights. This is necessary to avoid confusion and risk delay in important projects.

QnA12.19
Indexing the revenue driver to the price of steel would seem to be appropriate in so far as the extent of the indexation matches the steel cost in percentage terms. This would also help to reduce perverse incentives in the event that the actual price of steel diverges significantly (up or down) from that assumed when the revenue driver was initially set.

QnA12.21
We agree that buybacks relating to investment should be excluded from any incentive so that NG faces the costs of any delays that it is responsible for. It may be appropriate to link this to consents in some way. We acknowledge that an administered price is probably necessary to avoid NG facing unlimited costs but that this price should take into account the prevailing circumstances not simply refund capacity charges.

The issue of buybacks for maintenance has yet to be discussed in detail at EOWG and we expect to participate in these discussions. Our initial view is that some kind of sliding scale may be appropriate, subject to how the parameters are set. We would hope that the new arrangements would build upon the principles of modifications 60 and 66 and lead to better coordination of plant and pipeline maintenance.

QnA12.22
Flexibility over lead-times, see comments under QnA12.10. The commercial regime should be consistent with and be flexible enough to accommodate the physical realities of pipeline investment whilst recognising issues arising from developments by connectees too. This could be accommodated by review points with commercial linkages during the investment lead-time, but at some point no further revisions to the delivery date should be possible. If NG were able routinely to delay the delivery of committed capacity then there would be little point in seeking to align NG and connectee investment programmes as the risk of non-delivery by NG would remain. *In extremis* this could lead to developers signalling for capacity earlier than it is actually required to be confident of its delivery. This would not seem to be the best way forward. In theory the costs faced by NG should reflect those reasonably incurred by the connectee, but we recognise that in practice this is unlikely to be acceptable.

Qn12.23
We agree that it would seem logical to align the ‘option2A’ payment flows with the introduction of the enduring regime. There will be many issues arising from this and this should give sufficient time to consider these.