NIE Energy Limited
Power Procurement Business (PPB)

Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2010

Consultation Paper

SEM-09-072

Response by NIE Energy (PPB)

29 July 2009.

Introduction

NIE Energy – Power Procurement Business ("PPB") welcomes the opportunity to respond to the consultation paper on the Fixed Cost of a Best New Entrant Peaking Plant and the Capacity Requirement for the Calendar Year 2010.

General Comments

PPB is concerned at the change in the proposed Annual Capacity Payments Sum for 2010 which is approximately 15% lower than the amount for 2009. The reduction arises from both a reduction in the proposed BNE Peaker Cost and, for the first time, a reduction in the Capacity Requirement. This highlights the volatility of the CPM which was to be a more stable element of the market pricing and while we acknowledge the medium term review will consider how to reduce volatility, we do not consider the proposals for 2010 to be acceptable.

It should also be recognised that in addition to this proposed 15% reduction, capacity payments to generators will be further diluted in 2010 as a result of the overall increase in capacity (renewables and CCGTs at Aghada and Whitegate, offset by some closures/reductions). We estimate that this general increase in capacity available to the market will reduce payments to generators by around 8%.

In respect of the BNE Peaker cost, we recognise that the current methodology is inherently volatile and we accept that certain cost elements may have reduced since 2009 as a consequence of the current economic climate. However while PPB is not able to provide substantive comment on a number of the cost components used in the determination of the BNE Peaker cost, there are a number of elements, upon which we comment in more detail below, where we believe the costs are under-stated and which, when corrected, would result in a higher BNE Peaker cost than is proposed.

Similarly, we believe the WACCs proposed are too low and do not reflect the current cost of equity. The WACCs proposed are also much lower than those used for 2009 (0.94% for NI and 0.27% for RoI) which is also counter-intuitive in the current financial environment.

The reduction in the Capacity Requirement is also a concerning development in the determination. The general market expectation was that this would tend to increase correlated with demand and the CPM seeks to provide a long term signal to incentivise new entry. However, investment in generation is not a short term activity and the concept of reducing the requirement on the basis of a short term downturn in demand fails to recognise the longevity of generation investment decisions. This further highlights the volatility and risk for investors and would have a significant impact on investor views of risk in the SEM.

In addition, we note that the proposed Capacity Requirement for 2010 represents a reduction of 7.1% compared to the 2009 requirement whereas the reduction in demand is around 4% (and in peak demand of c3%). It is not clear why these two reductions are not more closely aligned.

PPB considers that it is unreasonable to reduce the Capacity Requirement and that where a calculation shows a reduction against the previous year's requirement, the previous year's requirement should set a floor. Hence PPB believes the 2010 Capacity Requirement should remain 7356MW.

The result of adopting our proposed principle that the capacity requirement should not reduce, allied to a re-assessment of the BNE price to use a more appropriate WACC and which adjusts those elements identified below (and any others identified by those more able to comment on other specific costs), will result in a more sustainable Annual Capacity Payment Sum pending the outcome of the medium term review that should provide a more stable and predictable determination methodology for future years.

Specific Comments

Technology Options

PPB has no particular comments on the technology selection adopted in the consultation paper although it is not clear why the size or particularly ramp rate of the plants is used in the selection criteria. Clearly the plant must comply with the minimum functional specification. However, that may differ from the TSOs "preferences" which may legitimately be driven by wider operational objectives although that is not relevant in terms of the BNE Peaking unit.

It is also unclear why the capacity of the proposed unit (the Alstrom GT13E2) has been inflated by more than 10 MW. Annex 1 of CEPA's final report shows the capacity as 180.2MW (which also aligns with the capacity used in the derivation of the BNE price for 2009 which was based on the same technology).

Investment Costs

The EPC costs have been set with a 3.8% multiplier based on UK experience. However, we would expect both the NI and RoI costs to be higher given many of the costs for a project in Ireland will be higher than in GB e.g. transport costs, labour costs, accommodation costs (since more skilled labour may be imported), etc. Furthermore, it is not clear why the EPC costs would be the same regardless of location and one would logically expect them to be different in NI and RoI.

We also find it difficult to accept there would be no water connection costs in N. Ireland. This may be down to the selection of a specific site at Belfast West whereas the costing should reflect more generic costing. However, even if the Belfast West site was the specific location, there would be some level of cost for water connection.

In relation to fuel storage, the assumption is to build storage and hold initial fuel stocks to enable 3 full days operation at full load. We presume this is the strategic level of fuel stocking that must be held for the unit. However, for the distillate only option, additional storage capacity and fuel stocking to enable the commercial operation of the unit would be required, i.e. such that the obligation to hold 3 days of strategic fuel stocks is not breached. Therefore the costs for the distillate only option should have higher EPC costs for larger storage and fuel handling facilities and also higher Initial Fuel Working Capital costs. We would suggest increasing the relevant costs by 33% for the distillate only options (to cover an extra day worth of fuel stocks to facilitate commercial operations on the distillate only configuration - gas is the "normal" commercial fuel for the dual fuel plant configuration).

Recurring Costs

The costs used to determine the cost of gas capacity are under-stated. Firstly, it is not clear why CEPA used the 2008/09 capacity charge rates for Northern Ireland when estimated 2009/10 rates were also published and are slightly higher. Revised charges for 2009/10 are due to be published soon and these figures should be used. Secondly, it is not clear that basing the gas capacity requirement on 4 hours operation is prudent. This is particularly relevant as gas nominations cannot be profiled and must be provided in a flat 1/24^{ths} profile. Hence it would be impossible to deliver the gas to operate the plant at short notice without either incurring gas balancing penalty charges or being restricted. There have also been occasions where peaking plant have operated for longer than 4 hours and we would suggest the gas capacity requirement should be based on a 12 hour operational requirement.

The Business Rates cost estimate for the Northern Ireland plants are slightly lower than are currently charged for generating units. We estimate them to be c€15k too low.

In line with our previous point in relation to the fuel stocking requirements for the distillate only option, the recurring fuel working capital cost would also be higher.

Economic and Financial parameters

The assumption is that the plant will have an economic life of 20 years and the determination of the annualised cost uses this tenure. It is not clear that financing for greater than 15 years is achievable in the Irish market and hence we believe this assumption should not be changed (and should be considered as part of the medium term review).

It is also not clear why a gearing of 60% is assumed. The general regulatory precedent adopted for network investment in GB (which would typically be viewed as a less risky investment) is 57.5% and therefore we believe a gearing of 60% is too high.

Proposed BNE peaker for 2010

PPB is not able to comment on many the detailed cost items that contribute to the determination of the cost of the BNE peaker. However, for those elements that PPB has commented upon above, all of them under-state the cost of peaking plant.

Ancillary Service revenues

A deduction is made to the BNE peaker cost to take account of the revenue the unit will earn from Ancillary service payments. While we agree with this principle, we have reservations about the level of revenue that the current AS proposals provide and our own modelling shows much lower AS revenue under the proposed arrangements than we receive under the current arrangements. Hence we have low confidence in the estimates shown and have great concern about the scope for volatility (i.e. revenue is particularly sensitive to running hours, load levels, etc.).

Our modelling also shows significant penalties under the Generator Performance Incentive (GPI) proposals and note that no charges (inc. Short Notice Declarations (SND) and Trip penalties) are assumed for the BNE peaker which again over-states the AS revenue it will receive. We believe greater sensitivity analysis is required in the determination of AS revenues and charges in relation to GPIs and SND/TPs should be deducted from the revenue.

Capacity Requirement for 2010

As noted in our general comments earlier, PPB has particular concerns about the volatility created in the CPM pot arising from the proposed reduction in the capacity requirement that results as a consequence of lower demand during the current economic downturn. Investment in the electricity industry is by its nature a long term one and the enduring strategy has been to provide long term signals to meet what has been a sustained growth in demand. PPB believes that it is unreasonable to reduce the requirement as a consequence of a short term demand reduction and that where the calculated requirement is less than that previously required then that previous level should be retained as a floor capacity requirement level until such time as demand picks up again. This provides the proper medium to long term signal that the CPM is supposed to deliver.

It should also be noted that as a consequence of the continuing increase in renewable capacity (driven by different incentives), overall installed capacity in the market will continue to increase and correspondingly, the CPM revenue for conventional plant will continue to be diluted and therefore exit or mothballing signals will remain.

On the specific data presented in the consultation paper, we have reviewed the annual energy production data for Northern Ireland shown on page 33 and the data until November 2007 concurs with our records from pre SEM. A simple analysis of the data for 2008 and 2009 lifted from the chart indicates the demand reduction to be 2.5% rather than 3.6%. It is also not clear what the “adjusted 2008” data represents as it seems to reduce the production for the first six months of 2008 (and indeed comparing the 2009 forecast against this adjusted dataset would show an increase in demand of c0.4%).

It is also unclear why the scenario used to predict demand growth assumes a more pessimistic view (than those expressed by the First Trust and Ulster Banks) of the prospects for economic recovery in Northern Ireland, thereby depressing demand and as a consequence the capacity requirement.

As we have noted in our previous responses, we also disagree that “target” forced outage rates are used and believe that actual rates (averaged over a number of years) should be used which more accurately reflects the risk to security of supply.

The treatment of wind is also unclear. Our interpretation of section 13.3.6 is that the wind is deducted off the load to produce a demand net of wind that is then used in CREEP against the generation to determine the LOLE and then “reference” plant is added to reach the target LOLE. A capacity credit for wind is then added back to determine the overall capacity requirement. If our understanding of the process is correct then it will understate the capacity requirement since it is in effect assuming fixed availability of wind on the basis of the profile. This is clearly not the case and a higher capacity requirement would be required to cover this risk.