Priti Dave-Stack
The Commission for Energy Regulation,
The Exchange,
Belgard Square North,
Tallaght,
Dublin 24.

29th July 2009

Your reference: SEM-09-072

Dear Priti

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

ESBPG is pleased to submit its response to this consultation. Below is a summary of the main points of our response followed by individual responses to the specific elements in the consultation paper.

Summary

ESBPG consider that the proposed €93m, or 15%, decrease in the 2010 capacity pot indicates higher levels of instability and risk within the structure of the SEM itself. The overall reduction in electricity demand has been well flagged by the Regulatory Authorities but ESB PG believes that a decrease of this magnitude entails a higher degree of regulatory risk than was heretofore indicated within the market.

The capacity income represents the bulk of the income any open cycle generator will earn in the market and a considerable proportion of a conventional generator's income also. The fact that the Regulatory Authorities (RAs) are signalling that revenue can fluctuate by such a significant amount year on year, makes a long term investment of this type and continued investment for medium term operation in the market a more risky proposition for conventional generators. At a time when raising capital for investment projects is more difficult than ever, this will be even further compounded by a lack of certainty in future incomes in the SEM, increasing the cost of finance yet further. This step change in additional regulatory risk and a step change in the available capacity for all market participants are not reflected in the WACC which has decreased in this year's calculation.

In particular ESBPG consider the proposed change in plant lifecycle from 15 years to 20 years to be arbitrary, inconsistent with previous years and incompatible with typical project financing structures. Given the current economic climate, the proposed WACC value is also unreasonably low. In addition, the BNE Cost of €85.16/kW is some 16% lower than ESBPG's own internal analysis.

Finally, we are concerned that the Capacity Requirement chosen is very low based on the current forecasts available. When the forecast median demand for 2010 is compared with the proposed capacity requirement, the implied required surplus is only 398 MW, an unrealistically low margin to use in the BNE calculation. Given this calculation's importance in determining the total capacity payment sum, and that the calculations are complex and not fully transparent or replicatable by market participants we would like to see a workshop held on this calculation as soon as possible.

Response to Consultation Questions

Chapter 4: Update on 'Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology'

ESBPG understand the decision to keep the methodology for the 2010 calculation the same as previous years. We look forward to the consultation paper later this year on the different options which will be evaluated as part of the medium term review.

Chapter 5: Technology Options

ESBPG recently engaged consultants to carry out a similar exercise, as that which was carried out by CEPA for the RAs, on an assessment of the peaking options currently available in the market. The GT Pro application was used in this review. We would welcome the opportunity to discuss our findings with the RAs.

One significant observation we make is that the EPC costs listed in Table 5.1 are inconsistent and considerably lower (by a factor of a third on average) than our analysis would suggest.

The CEPA report indicates that it looked at both the Large Combustion Plant Directive (LCPD) and the Industrial Emissions (Integrated Pollution Prevention and Control) Directive (IED IPPC) and considered investment based on a reasonable expectation of changes in environmental policy versus retrofitting of abatement technology into the future. However, the BNE paper only uses the Emission Limit Values (ELVS) set out in the LCPD, in particular that of $120Mg/Nm^3$ for distillate. ESBPG is surprised that the Consultation paper did not adopt the lower ELV of $90Mg/Nm^3$ for distillate as set out in the IED, given the clear requirement for this ELV into the future and that the proposed life expectation of this plant is set at 20 years.

Chapter 6: Investment Costs

As mentioned above ESBPG would welcome the opportunity to discuss our findings on investment cost estimates with the RAs.

Chapter 7: Recurring Costs Estimate

As above, ESBPG would welcome the opportunity to discuss our findings on recurring costs estimates with the RAs.

Chapter 8: Economic & Financial Parameters

ESBPG believe that in order to allow equal opportunity for new market entrants an Independent Power Plant (IPP) investor should be considered. By assuming that the investor is an integrated utility, investment by an IPP is potentially discouraged. We note that the current queue of conventional applicants in the Gate 3 process in ROI contains many IPPs which are not part of an integrated utility.

ESBPG also consider the change in plant life from 15 to 20 years to be arbitrary, inconsistent with previous years and incompatible with typical project financing structures. While we agree that the actual technical life of a plant may be greater than 15 years, our knowledge of the markets indicates that the project could only be structured and financed based on a 15 year plant life. Any Long Term Service Agreement arrangements would also not be for a twenty year period. The impact of this one change reduces the total capacity pot by over €66m, which has the end result of reducing the total income to peaker units by over 12% per annum.

Further to this, ESBPG note an apparent inconsistency in the consultation and would like to request further clarification on the following comment (page 23) relating to financing structure: "*It is assumed that an efficiently financed peaking plant would broadly seek to match the maturity of its debt profile to the anticipated project life of 20 years. Therefore it is assumed that an average tenor of 10 years on the new debt.*"

ESBPG agrees that an investor would seek to maximise the debt/equity ratio. The assumption of 60/40 may not be applicable to an IPP which would seek to place a higher ratio of debt. The RAs have assumed that the investor is an integrated utility.

ESBPG is of the view that the risk free rate is understated. A risk free investment for a 20 year period should be attracting a higher rate than 1.75% to 1.88%. A German bond investment for 20 years is currently attracting 4.25% return. By discounting this return using the ECB inflation target rate of 2% as a benchmark, a real rate of 2.21% is achieved. We believe this rate is more appropriate.

ESBPG also considers that the 3.5% debt premium is an inadequate figure for an IPP investor who would have to pay a considerably higher premium than this.

ESBPG is of the view that the equity risks assumptions also under represents the risks now facing a BNE investment. The only source of income has dropped 15% in one year and the return period has increased by 5 years or by a third. We believe the equity risk premium should be higher than in previous years and the indicated equity beta of 1.25 is over stated.

The headline impact of reducing the WACC figure from last years 7.9% is to reduce the total capacity pot by nearly €25m. The increased risk perception associated with a BNE is recognised in the consultation when it is noted that investors may "struggle to raise the necessary funding". There also is a lack of long term certainty over the main income stream for a BNE, evidence of which can be seen in the annual swings in income outlined in this consultation. This highlights the risk associated with investing in this market, when revenues are so susceptible to such dramatic change.

Chapter 9: Proposed Best New Entrant Peaker for 2010

It is proposed to use the NI Distillate option for the BNE. Given the queue of applicants in the Gate 3 process ESBPG believe that is it more likely that a BNE would in fact locate in ROI. However we consider that it is more appropriate to average the costs over the two locations rather than selecting one purely because it is the cheapest option. The Annual Capacity Sum calculation is not the correct place to deal with locational signals to the market.

Overall ESBPG's internal analysis would suggest that the cost for the Alstom GT13E2 machine is some 16% higher than the proposed figure of €85.16/kW. As previously stated, we would welcome a chance to present our findings to the RAs on our research in this area. We consider that our estimated costs accurately reflect current realistic market conditions.

Chapter 10: Infra marginal Rent

ESBPG agree with the proposal to assume zero infra-marginal rent for the BNE peaker. In our internal modelling analysis such a plant would normally not be scheduled to run. Any pool income a peaker earns typically will cover its marginal costs only, with no profit or rent being earned in the energy market.

Chapter 11: Ancillary Services

ESBPG consider that the proposal to use forecast incomes from the Harmonised Ancillary Services Arrangements, which is not yet in place and has no track record, brings uncertainty to the calculation of the BNE Cost. In the breakdown of forecast ancillary incomes (Table 11.1) it is assumed that the BNE will earn 80% of its income from "Replacement Reserve Unit De-Synchronised" payment, despite the fact that a decision on the division of the "Replacement Reserve" payment into two separate elements (i.e. synchronised and de-synchronised) has not yet been made.

Also, the Ancillary Services income predicted for the BNE at €5.05/kW is 82% higher than the income forecast for a peaker unit in the recent consultation "Harmonised Ancillary Services & Other System Charges" (SEM-09-062). Appendix B.3 in this paper estimates that a peaker unit will earn €2.78/kW in ancillary services revenue. This difference alone accounts for €15.5m drop in the capacity pot total. Furthermore, the proposed income level of €5.05/kW does not take into account any charges, (such as trips, short notice declarations, failure to provide reserve or generator performance incentive charges), which inevitably a generator will have to pay and in some cases may be very considerable.

	Typical 100MW Unit	Pro-Rated for 190.1MW	BNE Consultation
	AS Paper		
POR	9,888	18,797	24,309
SOR	14,357	27,293	63,459
TOR1	15,185	28,867	58,618
TOR2	7,592	14,432	29,309
Replacement Reserve	221,471	421,016	6,661
Replacement Reserve (DeSync)		0	764,362
Reactive Power (Leading)	2,278	4,330	6,833
Reactive Power (Lagging)	6,833	12,990	6,833
Total	277,604	527,725	960,384
Income per kW	2.78	2.78	5.05

Chapter 13: Capacity Requirement for 2010

ESBPG consider that the process used by the RAs and the TSOs in calculating the capacity requirement is non-transparent and difficult to understand and appreciate fully. The use of the CREEP software makes the calculation unreplicatable by market participants and makes an assessment of its fairness and accuracy impossible.

Taking the median forecast 2010 peak figures from the recently updated “Generation Adequacy Report 2009-2015” (for ROI) and SONI’s “Seven Year Generation Capacity Statement 2009-2015”, gives a combined expected peak of 6,434MW for the system in 2010. This leaves just a 398MW surplus when compared with the proposed figure of 6,832MW for the capacity requirement in the system. ESBPG consider that this margin is very low.

The treatment of wind in the calculation is particularly of interest. It is not clear what capacity credit is being used for wind currently. And at the same time the anomaly still remains that wind generators are taking from the pot based on their availability (~35%) and yet their contribution to adequacy, and so the determination of the pot, is only counted as a much lower capacity credit percentage. ESBPG are aware that this issue is being dealt with in the medium term review by the RAs.

ESBPG request that a workshop be held on the process and calculation of the 2010 capacity requirement figure so as to ensure full transparency in the process.

Chapter 14: Indicative Annual Capacity Payment Sum for 2010

The decrease in capacity requirement from the 2009 figure of 7,356MW has the impact of reducing the capacity pot by €42m or 7%. The capacity income represents the bulk of the income any open cycle generator will earn in the market, and a considerable proportion of a conventional generator’s income also, as was seen in Chapter 9 of the “Market Monitoring Unit Public Report 2009” (SEM-09-039) where the actual revenues of generators for 2008 were analysed. The fact that the Regulatory Authorities (RAs) are signalling that revenue can fluctuate by such a significant amount year on year, makes a long term investment of this type and continued investment for medium term operation in the market a more risky proposition for conventional generators.

Given the importance and impact of this on the revenue streams for all generators, ESBPG request that a workshop be held on the process and calculation of the capacity requirement figure as soon as possible.

If you have any questions or would like to discuss any of the matters raised further please do not hesitate to contact me.

Yours sincerely,

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