BORD NA MÓNA ENERGY LIMITED

**Submission by Bord na Móna Energy Ltd.**

**on**

# Fixed Cost of a Best New Entrant Peaking Plant for the Calendar Year 2009

# Response to SEMC Consultation Paper

# AIP/SEM/08/083

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# Fixed Cost of a Best New Entrant Peaking Plant for 2009
# Response to Consultation

Bord na Mona Energy Ltd, (BnM), welcomes the opportunity to respond to the recent consultation paper on the Fixed Cost of a Best New Entrant Peaking Plant for 2009.

This parameter is one of the two factors used to determine the Annual Capacity Payment Sum, (ACPS), which represents the total amount of money for the year disbursed through the Capacity Payment Mechanism, (CPM). The other factor is the Deemed Capacity Requirement for the year, (an indicative value of the capacity requirement for 2009 is given in Section X of the consultation paper). The CPM is a key instrument of the market in remunerating some or all of the fixed annual and capital costs of generating units participating in the market, and acts as an important signal for the construction of new capacity when required.

This paper responds to individual areas of the consultation, including a discussion on the indicative capacity requirement in Section X of the paper, (as it is unclear if there will be a separate consultation process in relation to that factor). The conclusion highlights key aspects of the mechanism used to set the capacity payments sum that need to be addressed to ensure the efficiency of long term price signalling for the provision of adequate generation capacity in the medium term.

A key consideration in assessing the fixed cost element of  a BNE peaking plant, is that this plant is likely to have a capacity factor in the market in the range of 0 – 2%. Such plant will be required primarily to provide system replacement reserve, given the level of penetration of intermittent generation sources, such as wind, required to deliver the Governments RES-E targets. As such practically all of the revenue derived by a peaking plant will come from capacity payments.

The CPM as currently structured is subject to a number of key variables which are fixed primarily by regulatory discretion. BnM, therefore, consider that there is significant potential for volatility in the capacity payments received in the market and the uncertainty this creates significantly increases the risk profile of a BNE peaking plant. We therefore believe that there is significant risk of under recovery of investment costs in peaking plant, and this must be reflected in the process used to derive the fixed cost of the BNE peaker, particularly in assessing the WACC element. If appropriate consideration is not given to the risk profile of such plant, BNM is of the opinion that there is a danger that timely investment will not be made in the delivery of flexible peaking capacity, which will be required for system security reasons, if the RES-E targets are to be achieved.

BnM considers that the potential for volatility in the size of the annual capacity payment pot is driven principally by technology options and choices, estimated EPC prices, infra marginal rent deductions, the accepted volume of generation capacity required and the WACC calculation. Each of these items are addressed in turn in this paper.

**(1) Technology options (Section IV)**

The technology selection reduces to a comparison of the Base Case Fixed Cost per year of a number of units within a range of unit size and having suitable dynamic characteristics for offering replacement reserve (ability to reach full load in twenty minutes).

There is limited transparency in the development of the Base Case Fixed Cost per year, which is used as the ultimate criteria to select the Siemens unit as the BNE peaker. The detailed breakdown of the capital and fixed operating costs of a shortlist of two or three units should be developed to allow more informed comment on the relative costs before finalising the decision on the chosen technology.

In addition, there is a discussion later in the consultation document that indicates that there is significant volatility in the Base Case estimates presented. In this case, it would be more accurate to perform the screening analysis on the basis of the median estimate for each plant type, rather than the lowest estimate available, particularly if there is a significant difference in the range of estimates for different units. The reason for discounting the Alstom 13E2, (2008 BNE peaker technology selected) unit before other units is not explained clearly; it is discounted before some of the other units even though it has the second lowest Base Case Fixed Cost per year of all the units evaluated, based on the limited data supplied in the consultation document.

**(2) Economic and Financial Parameters (Section V)**

BnM were surprised by the estimates for the Weighted Average Cost of Capital (WACC), which has fallen from a level of 7.83% in the 2007/8 calculation to 7.24% for the 2009 estimate. This fall in the estimated cost of capital runs contrary to the current global economic situation, which has seen severe reductions in liquidity in financial markets and significant increases in the cost of credit.

The difference from last years rate is primarily due to an almost one percent drop in the Nominal Risk Free Rate from 5.53% to 4.58% which consequently drives significant reductions in the real cost of debt and the real cost of equity. We do not consider it appropriate to use a spot rate for this figure, as it the daily variance is significant relative to longer term averages. There has been a significant underlying upward trend in this value over the last number of months, which should be reflected in the final calculated WACC, and BnM considers that 4.8% is a more appropriate rate at present.

The value of the debt risk premium has been adjusted by 0.25% which does not accurately reflect the current cost of securing credit in the financial markets. Bord na Mona's analysis and experience in the private placement market suggests that the debt spread should be at least 2.75%.

The paper states that Asset Beta value of 0.6, used to reflect the business risk for developers compared to returns from the global equity markets, is in line with international estimates which generally range from 0.5 to 0.8. We would feel that the risk profile associated with the BNE peaker operating in the SEM, a fledgling market with significant barriers to project development, such as size of market, perceived dominance of incumbents, and access to grid connections, this value should be at the upper end of the international scale. We therefore consider 0.7 a more appropriate value for the Asset Beta value for development projects with the risk profile associated with the BNE peaking plant.

BnM do not consider it appropriate to reduce the equity risk premium due to comparisons with different industries, with different risk profiles and investment time horizons. As stated, the cost of equity, through appropriate selection of the equity risk premium and the equity beta, should reflect the risk of investing in a developing market during a period where the returns from low risk investments are on the increase.

Taking all of these factors together, our estimate for the WACC indicate that the value should be in the region of 8.4%

**(3) Investment Cost Estimate (Section VI)**

Site procurement costs have dropped significantly from the previous BNE peaker plant, down from €2.5m in 2008 to €1.343m). This may be related to a reduction in the size of the site area required due to the change in turbine selected. Our view is a site area of 4,800m$^2$ is too small to accommodate the gas turbine and generator unit, storage tank(s) and bunding for 100 hours fuel storage, (~ 4,500m$^3$), fuel unloading area, fuel forwarding, switchyard, control/personnel building, spare parts store and appropriately sized laydown areas for construction and maintenance. BnM is also of the view that the proposed cost does not account for the significant premium that would attach to an appropriately zoned site, within 2km of a node that has sufficient capacity to connect a 170MW unit. We consider that an appropriate value for site procurement is at least €3m.

The pre – financial engineering costs are underestimated for a project of this scale. Our experience of the costs involved in planning, preparation of EIS, procurement, and financing and legal services would be closer to €2m for a project of this type.

The proposed connection costs assumes that the 110kV grid is capable of connecting a unit of this size, which is practically unfeasible, due to the size of the unit, and the number of 110kV nodes that have sufficient available connection capacity on the system at present. BnM feel it is more appropriate to estimate the connection costs on the basis of a 220kV connection, with the necessary adjustments for site selection, and connection costs. BnM provisionally estimate the costs have increased to €4m.

BnM have reviewed the history of the assessment of the capital costs of the BNE peaker to put the current proposal in context. The Regulatory Authorities commenced the consultation process on the fixed cost of a BNE peaking plant in late 2006 in preparation for the derivation of the 2007 Annual Capacity Pot. In the final decision paper (AIP/SEM/07/187) the EPC price for an Alstom GT13E2 plant, which included electrical connections, and a 2% developers contingency, was estimated at ~€69m, with the plant component of this estimate amounting to €66.7m. This figure allowed a spend of €3m for a SCR $NO_x$ scrubber. In estimating the cost of the BNE peaking plant for the purpose of deriving the 2008 annual capacity pot, conducted in mid 2007, these estimated costs were not revisited. The Unadjusted BNE cost for 2007 was calculated at €85.04/kW/yr, and increased marginally to €85.95/kW/yr for the 2008 calculation.

In 2007 during the course of initial enquiries conducted by BnM with equipment suppliers the plant costs for the 13E2 were indicated at least 15% (€80m) above that fixed in the final decision paper (AIP/SEM/07/187)on the fixed costs of a BNE peaker. It is well recognised within the industry that in the subsequent 12 months equipment prices in general have increased substantially from the 2007 levels, in some cases by as much as 30%, depending on the plant type. BnM contends that the 2007 EPC price for the 13E2, used to set the 2008 capacity pot, should have been in the region of €90m and not the ~€67m used in the calculation. Based on this evidence we contend that the current approach to assessment of the EPC price is not sufficiently robust

Given the fact that there is limited transparency in the development of the Base Case Fixed Cost per year, and that the technology of choice is no longer the Alstom 13E2, it is very difficult to make specific comparisons with elements of the cost base, such as the plant technology itself in the current consultation. This must be addressed in future consultations to allow specific comparisons of cost elements on a year on year basis, which will contribute to a more robust assessment of the EPC price component.

BnM’s research indicates that the current price for an EPC for the Siemens SGT5 2000E fired on distillate is at least €80m. The plant output on distillate at approx 173MW gross, (ISO) which, allowing for the same adjustments as used in the paper, gives a net plant output of approx 164MW.

The capital costs for distillate storage ( €906k) is too small for on site storage of 100 hours, (~ 4,500m$^3$) including appropriate bunding, and fuel off loading equipment, assuming that the necessary fuel forwarding and cleaning plant is included in EPC. We estimate that the real cost of these facilities to be approx €2m.

The Regulatory Authorities have acknowledged at the end of this section in the consultation document, that due to the volatility of the market and the “significant degree of subjectivity in estimating the required investment costs” that the estimated capital costs are not reliable. This calls the entire methodology of estimating the BNE peaker costs into question. The error range on a number of estimates from reputable sources is given as 36%. This level of uncertainty could not be tolerated by a developer agreeing an EPC contract. If the mechanism for estimating the capital cost of the BNE peaker is not sufficiently robust to more accurately estimate the development costs for a single unit plant, it may be appropriate to consider an alternative approach to estimating the cost component of the plant.

Taking the capital costs and cost of capital in isolation, and without factoring in our views expressed later in this paper in relation to the estimations on recurring costs and the deemed capacity requirement, the final BNE peaker cost should be in the region €96/kW/yr in the present environment. This would equate to an Annual Capacity Payment Sum of approx €700m, (see table in Appendix 1).

**(4) Recurring Cost Estimates (Section VI)**

Table 1 compares the recurring costs included in the 2009 BNE peaking plant paper with those of the final 2008 BNE costs

| Recurring costs | Units | BNE 2008 | BNE 2009 |
|---|---|---|---|
| LTSA | € '000 | 578 | 1,176 |
| Owner's general and admin costs | € '000 | 993 | |
| Transmission charges (& SEMO) | € '000 | 795 | 935 |
| Insurance cost | € '000 | 1,880 | 1,008 |
| Rates cost | € '000 | 1,898 | 1,315 |
| Fuel Storage | € '000 | 115 | 168 |
| **Total** | **€ '000** | **6,259** | **4,602** |

**Table 1** Comparison of Recurring costs

The first point to be made is that the costs are aggregated under different headings compared to the structure used in previous consultations, which reduces the transparency of comparing the revised costs with previous years estimates.

The overall result is a drop of over 26% in the estimates of fixed costs for the BNE peaker from the 2007/8 estimates. It is difficult to compare individual line items directly, but significant reductions in the estimates for insurance, operation and maintenance costs and rates are proposed. It would seem that the biggest percentage drop is in insurance costs, though an exact comparison between the figures is not possible, as the estimate for 2009 includes other miscellaneous costs. BnM have not observed these levels of reduction in the insurance market for its current power plant operations.

Rates costs have fallen by 30% with no explanation for the scale of the reduction. The overall estimate for O&M, including Long Term Service Agreements, is also reduced by approx 25%. We content that in the current climate it is difficult to accept that the fixed costs of running a plant, which has not changed in function and only marginally reduced in size from previous assessments, have fallen to the extent indicated in the consultation. The Regulatory Authorities should give a much more detailed explanation of the year on year decrease in these costs.

**(5) Ancillary Services Revenues (Section VII)**

The level of Ancillary Services (AS) revenue for the BNE peaker plant has grown to €7.04/kW/yr, a rise of 13.9% from the 2008 level. This is more than double the year on year increase in the AS rates from 2007 to 2008. Again there is no transparency in the process used to generate this estimate. In particular, the document does not explain the types of services that the BNE unit generates revenue from, or the manner by which reserve requirements and availability is modelled. This item area should be developed more clearly in order to enable more detailed year on year comparisons and analysis of longer term trends.

**(6) Addressing Volatility (Section IX)**

The proposed approach to forecasting the EPC costs using an historical trend, or other forecasting method, is not where the focus of managing volatility should lie. Whilst it is acknowledged that the EPC contract is the biggest single line item in the estimation of the BNE cost, it accounts for approx only half the capital costs and just over a third of the final BNE price.

The analysis on historical turbine prices is unsatisfactory, and is not considered robust enough, as the discussion focuses on an average price for units that are originally priced in different currencies. The linear regression on the price averages acts to show falling average prices in 2009, which are driven by a fall in prices from 2002 to 2004 and a weakening dollar since 2005. This analysis does not adequately reflect the significant upward pressure on all the individual turbine prices as seen from 2005 to date. The modifying effect of the euro\dollar exchange rate belies the fact that this rate could equally be a source of adverse volatility within the timescales required to develop a project of this nature

The largest variation in the price elements from 2008 to 2009 was the significant reduction in the estimates of recurring costs (fixed annual costs) for the plant which reduced by approx 25% year on year. The other significant potential source of volatility which did not arise this year, (but had a significant effect in the 2007 estimates) is the infra marginal rent calculated from estimates of margins earned through participation in the energy market.

**(7) Capacity Requirement (Section X)**

The indicative capacity requirement for 2009 is stated as 7,320 MW. The year on year increase is approx 1.5% which is indicated as primarily due to load growth.
The first point to be made in relation to this factor is that it plays an equally important role as the cost factor in the setting of the capacity payment sum, and should therefore have a discussion of the main factors used in its estimation, in this or another consultation process.

The second point to note is that this level of deemed capacity predicts a reserve margin at peak load of approx 3.5%, based on the peak load used for the 2009 Plexos market model runs, as published by the Regulatory Authorities in April 2008. It is inconceivable that the Regulators and System Operators would run the system with such a tight margin whilst trying to ensure an appropriate security of supply standard. The key element in this underestimation of capacity is the target level of ~4.2% forced outage rates for the portfolio are significantly lower than current rates reported by Eirgrid, averaging 8.7% from Aug 07 – Jun 08 excluding long term outages at Poolbeg unit 3 and Turlough Hill unit 1.

BnM acknowledge that there is significant room for improvement in the availability of the current portfolio, but contends that this is primarily due to the age profile of the plant on the system. However, setting an unrealistic target for improvement, in the short to medium term depresses the capacity pot and acts as a disincentive to on the provision of the new plant that will improve the availability performance of the portfolio.

**(8) Conclusion**

The discussion on the recognition and need to address the volatility in estimating the BNE peaker costs is welcome. The consequences of underestimating the annual capacity sum may have a short term benefit in terms of depressing wholesale prices, but this approach will ultimately lead to underinvestment in new plant, shortages in supply and higher energy prices to consumers in the future. We contend that the emphasis on the treatment of volatility should be placed on the resultant annual capacity payment sum, rather that looking at one or other element of one of the constituent factors.

It is our view that the application of the current approach does not fair well when judged against the criteria of capacity adequacy and efficient long term price signalling, which were two of the key criteria used in the evaluation of the CPM. The current approach is not being applied in a sufficiently robust manner to accurately reflect the cost components of developing a BNE peaking plant on the system at present.

In terms of capacity adequacy, the underestimation of the required capacity based on unachievable levels, in the short to medium term, of portfolio availability act to depress the pot which weakens the market signal for the delivery of new plants to replace older units in the market.

The efficiency of the longer term market signal to attract new development is reduced by the variability in the development structure, and price levels in the estimation of the price of capacity over the first two years in the market. The most significant problem with the mechanism from a longer term planning perspective is the fact that it is set on an annual basis, with no tangible way of predicting variations from one year to the next

The principle of infra-marginal rent reduction in the BNE peaker price estimate acts to remove the price signal associated with tightening reserve margins. In an energy only market, the profit earned from the scarcity premium bid by a peaker in the market would act as the market signal for new entry to that market. In the SEM CPM design, this profit is removed from the CPM through the infra-marginal rent reduction to the price factor, which depresses the Capacity Payment Sum as reserve margins deteriorate.

The issues identified with the current approach to the CPM could lead to significant capacity shortages in the medium term if not addressed sooner rather than later. The key issues to address are a more realistic estimate of capacity requirement, and a rebalancing of the treatment of the controls on the cost element to ensure it acts to signal the timely addition of capacity in line with the original requirements of the mechanism. Once these issues have been adequately addressed, the last piece in the jigsaw is the need to give longer term visibility of the size of capacity pots to enable a level of confidence in the market that will allow the timely investment in the types of generation plant required by the system.

For and on behalf of
Bord na Mona Energy Ltd

John Reilly,
Head of Power Generation & Renewables…………………………………….
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## Appendix 1

### Capital cost of BNE Plant

| | |
|---|---|
| **Site Procurement** | 3,000 |
| | |
| **Pre Financial Close** | |
| Owners manpower costs up to contract award | 900 |
| Financial, legal costs, engineering, consultancy and EIA | 2000 |
| **EPC costs** | |
| EPC | 80,000 |
| Electrical Interconnection | 4000 |
| Distillate facilities | 2000 |
| **Post Financial Close** | |
| Owners manpower during construction | 1200 |
| Taxes, insurance during construction | 300 |
| Purchased electricity fuel during construction | 300 |
| T&SC Fees | 6 |
| Working capital (first fill) | 3000 |
| Contingencies | 1720 |
| Interest during construction | 3842 |
| **Total** | **102,268** |

### Fixed Cost of BNE Peaker

| | |
|---|---|
| **Annuitised Capital costs** | |
| Total Project Development costs | 102268 |
| Payback Period (years) | 15 |
| WACC | 8.40% |
| **Annuitised Capital costs** | **12241** |
| | |
| **Recurring Costs** | |
| Operations and Maintenance | 1176 |
| Transmission and SEMO charges | 935 |
| Insurance and Miscellaneous cost | 1008 |
| Rates cost | 1315 |
| Fuel Storage | 168 |
| **Sub - total** | **4602** |
| | |
| **Total Annual costs** | **€16,843** |
| | |
| **Fixed BNE costs/kW** | **€102.70** |
| | |
| Infra-marginal rent | 0 |
| Ancillary Services | 7.04 |
| | |
| **Final Adj BNE cost** | **95.66** |
| | |
| **Deemed Capacity (MW)** | **7320** |
| | |
| **Capacity Pot, (€m)** | **700.3** |