# Single Electricity Market

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

## Consultation Paper

1st July 2009

AIP/SEM/09/072

# 1 CONTENTS

## 2 INTRODUCTION

On 1 November 2007 the Single Electricity Market (SEM), the new all-island arrangements for the trading of wholesale electricity, was successfully implemented. The SEM is a gross mandatory pool which includes a marginal energy pricing system and an explicit Capacity Payment Mechanism (CPM). The CPM is a fixed revenue mechanism which collects a pre-determined amount of money (the Annual Capacity Payment Sum) from purchasers and pays these funds to available generation capacity in accordance with rules set out in the Trading and Settlement Code (T&SC). The value of the Annual Capacity Payment Sum is determined as the product of two numbers:

- A Quantity (the Capacity Requirement), determined as the amount of capacity required to just meet an all-island generation security standard;

and

- A Price determined as the fixed cost of a best new entrant (BNE) peaking plant.

The methodology for the determination of the fixed costs of a BNE peaking plant was set out by the Northern Ireland Authority for Utility Regulation (NIAUR) and the Commission for Energy Regulation (CER), together the Regulatory Authorities (RAs), in two decision papers published on the All-Island Project website in 2007[1]. Subsequently the Regulatory Authorities reviewed these costs in relation to the determination of the value of the Annual Capacity Payment Sum for the calendar year 2008[2]. The same process was used for the calculation of the fixed costs of a BNE peaking plant for 2009 and now 2010. The consultation paper and final decision paper for 2009 were published on the AIP website[3]. The Annual Capacity Payment Sums for 2007, 2008 and 2009 are summarised in Appendix 1 of this paper.

This Consultation Paper sets out:

1. The options for the BNE peaking plant for 2010 and proposes a technology option. The paper then explores the fixed costs associated with the proposed technology option as well as the financial costs and sets out the proposed resultant value in €/kW/year.

2. The Capacity Requirement for 2010 and the approach used for its determination.

On 9th March 2009 the SEMC published a consultation paper titled '*Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology Consultation Paper' (SEM-09-023).* The RAs have reviewed the large number of responses and have noted a varied number of preferences for the options listed in the consultation paper. Some respondents

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[1] Fixed Costs of a New Entrant Peaking Plant for the Capacity Payment Mechanism, Decision and Further Consultation Paper (AIP/SEM/07/14);

Fixed Costs of a New Entrant Peaking Plant for the Capacity Payment Mechanism, Final Decision Paper (AIP/SEM/07/187)

[2] Annual Capacity Payment Sum: Final value for 2008 (AIP/SEM/07/458)

[3] Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement, and Annual Capacity Payment Sum for Calendar Year 2009 Decision Paper (AIP/SEM/08/109)

provided alternatives to those proposed in the consultation paper and suggestions on how these could be implemented. In light of the varied preferences and comments received to the consultation paper, the RAs have decided to amalgamate this matter with its more comprehensive review of the CPM and therefore did not apply any of the options outlined in the consultation paper to the 2010 calculations. This area is discussed in further detail in Section 4 of this paper. The same methodology as applied in previous years will be used in the determination of the fixed costs of a BNE peaking plant for 2010.

The RAs have engaged Cambridge Economic Policy Associates (CEPA) in association with Parsons Brinckerhoff (PB) to assist in the calculation of the fixed costs of a BNE peaking plant for 2010. The RAs are keen to ensure that the process used for the calculation of the BNE Peaker is as transparent as possible and with this in mind hosted a workshop with market participants on 12th May 2009 where CEPA and PB outlined their proposed approach and took feedback from attendees.

This paper covers the key recommendations made by CEPA/PB, and provides the RAs position on the various components.

The structure of this document is as follows:

**Section 2** introduces the consultation paper and describes the contents within;

**Section 3** sets out the background to the development of the CPM;

**Section 4** provides and update on the consultation paper ''*Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology Consultation Paper' (SEM-09-023);*

**Section 5** examines the technology options available in considering which generation set represents a best fit for the BNE peaking plant;

**Section 6** presents the investment cost estimates for the BNE peaking plant;

**Section 7** looks at the recurring costs a BNE peaking plant could expect to incur;

**Section 8** considers the economic and financial parameters to be used in the evaluation;

**Section 9** contains a proposal of the Best New Entrant Peaker for 2010;

**Section 10** presents the Inframarginal Rent for the chosen BNE technology;

**Section 11** presents the Ancillary Service revenues calculations for the chosen BNE technology;

**Section 12** provides an indicative value for the proposed BNE peaking plant fixed cost;

**Section 13** details the calculation of the Capacity Requirement for 2010;

**Section 14** provides an indicative value for the Annual Capacity Payment Sum for 2010 based on the proposals in this document;

**Section 15** invites comments and views;

**Appendix 1** summarises the Annual Capacity Payment Sum for 2007, 2008 and 2009

**Appendix 2** compares the costs for the 2009 BNE Peaker and the 2010 BNE Peaker;

**Appendix 3** contains a copy of the CEPA report provided to the RAs for the 2010 Calculations.

# 3 BACKGROUND

In May 2005 the Regulatory Authorities (RAs) set out the options for the Single Electricity Market (SEM) Capacity Payment Mechanism (CPM)[4]. In the paper the RAs indicated their proposal to develop a fixed revenue capacity payment mechanism that would provide a degree of financial certainty to generators under the new market arrangements and a stable pattern of capacity payments. The principles outlined were incorporated in the design of the CPM and in the Trading and Settlement Code.

In March 2006[5] a consultation document was published that incorporated a more detailed consideration of the comments received on the design of the CPM and put forward a number of alternative options for the CPM. The processes that the RAs proposed for determining the annual capacity payment and the general process by which the input parameters to the CPM would be set were also covered.

The March 2006 paper reiterated the proposed outline of the CPM for the SEM suggesting that annual capacity payments should be fixed and that the annual fixed sum be divided into a number of within-year pots ( i.e. Capacity Periods). The paper also set out proposals for the determination of the Annual Capacity Payment Sum (ACPS). The paper proposed that the annual aggregate capacity payments should be set by multiplying an appropriate level of required generation capacity by the relevant fixed costs of a best new entrant peaking generator. The RAs proposed that, for the purposes of determining the ACPS, the cost of new entrant generation should be assessed in terms of a 'Best New Entrant' (BNE) peaking plant.

The Regulatory Authorities also determined that the resulting cost should be adjusted to account for the inframarginal rent the BNE peaking plant may derive through its sale of energy into the pool, as well as the estimated revenues the plant may derive through its operation in the Ancillary Services markets. The infra-marginal rent was to be determined through a series of Plexos market model runs, configured with the most up-to-date data from the Market Modelling Team based in CER. The Ancillary Services revenues were to be determined by reference to the prevailing Ancillary Service arrangements in the jurisdiction in which the BNE peaking plant was determined to be located.

The resulting cost of the BNE peaking plant calculated would be expressed in €/kW per year (as an annualised payment) and multiplied by the capacity requirement to calculate the ACPS.

[4] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?page=2&article=0e5940cb-4c5d-4e01-982d-2b3587c33d2d

[5] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?page=2&article=94ef0599-001a-4923-a706-7682f76ec79b

## 4 UPDATE ON 'FIXED COST OF A BEST NEW ENTRANT PEAKING PLANT CALCULATION METHODOLOGY'

### 4.1 BACKGROUND

On 9th March 2009 the SEMC published a consultation paper titled ***Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology Consultation Paper.*** The purpose of the consultation paper was to propose options to address a key concern raised by industry participants regarding the stability of the capacity payment pot due to the annual determination of the Best New Entrant Fixed Cost (BNEFC) and the Annual Capacity Payment Sum (ACPS).

The consultation period has concluded and total of 18 responses were received. The RAs appreciate the consideration given by respondents to the consultation paper.

The consultation paper left open the implementation timeframe of the options consulted but explicitly stated that should the SEMC decide to adopt a more radical approach then the practicalities of implementing such an option would be amalgamated within the medium term review of the CPM flagged for later 2009-2010.

### 4.2 GENERAL RESPONSES

The RAs have reviewed the responses and have noted a varied number of preferences for the options listed in the consultation paper. Some respondents provided alternatives to those proposed in the consultation paper and suggestions on how these could be implemented.

As a general observation a number of respondents questioned why this particular aspect of volatility was being addressed early and separate from the wider medium term review and reserved judgement until the fundamental review of the CPM was undertaken. A number of respondents also suggested that the matter should be considered holistically and within the context of the matters that will be reviewed in the medium term. Some respondents suggested that if the RAs were in favour of implementing a change for the 2010 pot, then Option Two [6] could be used, but only as an interim measure prior to the full implementation details of the enduring Option being implemented. Overall most respondents argued that this matter be considered within the medium term review and some respondents questioned if there really was an issue with the BNE fixed cost and suggested that very limited changes to the methodology was required.

[6] Under this option – it was proposed that the BNEFC would be calculated on an annual basis but some components cost remain constant for a number of years Use the current methodology to calculate the BNEFC but with some constituent elements kept unchanged for a period of, 3 or 5 years for example.

## 4.3 NEXT STEPS

In light of the varied preferences and comments received to the consultation paper, the RAs have decided to amalgamate this review with its comprehensive review of the CPM planned in the medium term. The RAs have decided on the following approach on this subject.

1. The capacity pot for 2010 will be set following the same methodology applied in establishing its value in previous years.
2. A consultation paper on the short list of options proposed to be brought forward for evaluation in the medium term review will be published later this year.

# 5 TECHNOLOGY OPTIONS

The RAs employed CEPA in association with PB to assist in the calculation of the fixed costs of a BNE peaking plant for 2010. Their independent report is detailed in Appendix 3 of this document and is referenced throughout this paper.

## 5.1 APPROACH USED FOR SELECTION OF TECHNOLOGY

The RAs held a number of meetings and workshops with CEPA/PB where the approach to be used for the selection of the technology was discussed. In the interests of consistency the RAs required CEPA/PB to build on the approach used in previous years. The approach used by CEPA/PB is documented in Section 2 of their report and was presented to market participants at the public workshop held on 12th May 2009.

The approach and subsequent selection of the BNE plant is influenced by the following considerations

- The BNE is a notional plant that would serve the last MW on the system.
- The plant is expected to operate no more than 5% of the time.
- The plant will enter the SEM in 2010.

In addition to conventional plant, consideration was also given to other options such as pumped storage, interconnector and second hand units. Based on a query raised at the workshop held on 12th May 2009, Aggregated Generator Units (AGUs) were also considered. AGUs are units which combine smaller more geographically dispersed generation technologies.

In the 2009 BNE Peaker consultation process there were a number of comments and opinions on whether the fuel used by the BNE Peaker would be distillate or gas. The RAs have taken note of these comments and have considered both fuel types in the section of a suitable technology.

## 5.2 CRITERIA FOR SELECTION

Similar to previous years, a long list of potential options was developed by CEPA/PB to which the criteria for selection were then applied. The methodology employed was to use a series of ‘pass/fail’ criteria to the long list in order to reduce the number of feasible options. The Transmission System Operators (TSOs) were also engaged in the process and feedback was sought from them on the ideal size and ramp up rate of the plant. This process resulted in a short list where a more detailed analysis could be carried out.

The long list of potential options contained 25 conventional plant types of different manufacturers, type and size.

The criteria used to reduce the long list to a short list are as follows:

- The technology option must be commercially available
- The technology option must have a proven track-record (typically defined as 3 examples of over 8000 running hours)
- The unit sizes must be between 30 and 200MW
- The technology option must ramp up to full load in less than 20 minutes
- The technology option must be able to fire liquid fuel

- The technology option must meet all environmental requirements (e.g Maximum NOx value for distillate firing = 120 Mg/Nm$^3$ and for gas firing = 50 Mg/Nm$^3$)

These criteria are discussed in the CEPA/PB report in section 3.3

## 5.3 SHORTLIST OF TECHNOLOGY OPTIONS

Using the criteria discussed in section 5.2 the number of options was reduced from 25 to 13. In order to further reduce the list of options to a manageable number to allow a detailed analysis, a comparison of equipment costs was carried out. The costs were based on the equipment costs published in the Gas Turbine World 2009 GTW Handbook. The efficiency levels of the 13 plant were also considered, however based on comments received at the workshop on 12th May 2009, less emphasis was put on the efficiency. Considering the relatively low running time of the plant, a rational investor would allocate a larger weighting to cost rather than plant efficiency. As a result of this analysis a recommended short list of options was proposed and a detailed analysis of these units was undertaken. The short listed units are:

- 1 x Alstom GT13E2
- 1 x SGT5-2000E
- 4 x GE LM6000 PC Sprint
- 3 x P & W FT8 Swift Pac 60 (wet)

Further details on the selection of these units are discussed in the CEPA/PB report in section 3.4

## 5.4 OTHER TECHNOLOGY OPTIONS CONSIDERED

As determined in previous years, pumped storage was not considered due to the limited number of suitable sites and the desire for relative stability of the CPM pot year on year.

The Interconnector was also deemed as unsuitable as there is a level of uncertainty as to whether the Interconnector would definitely be able to supply the last MW of load in all situations.

The AGU’s available capacity is a function of the onsite load and this cannot always be guaranteed. Therefore the AGU may not be appropriate for the BNE Peaker. However, the AGUs can be investigated further and considered within the scope of the CPM Medium Term Review.

In terms of availability and appropriateness of using second-hand units for the BNE Peaker, PB investigated what hardware was currently available. Based on their investigation, they recommended that a second-hand unit would not be feasible for the 2010 BNE Peaker. This is discussed in the CEPA/PB report in Section 3.3.1

## 5.5 ENGINEERING, PROCUREMENT & CONSTRUCTION (EPC) ANALYSIS

Based on the short listed technology options detailed in section 5.3, a more detailed cost analysis was carried out of the shortlist to consider the investment costs for each option. As mentioned above, each of the four options was analysed taking into consideration the costs for the units running on gas and the costs for the units running on distillate.

One of the largest areas of costs is in relation to the EPC. As a result of consultation last year, the RAs wish to provide transparency in relation to the calculation of the BNE Peaker for 2010. Several comments queried whether standard software (such as GT PRO) was used to estimate the EPC cost and if so how this process was applied. With this in mind, the RAs requested CEPA/PB to where possible use actual experience they have in delivering projects in their cost estimates..

CEPA/PB carried out a detailed analysis of the four options short listed using the software package GT PRO. CEPA/PB took the values of EPC costs from the GT PRO tool. They then compared these with relevant actual costs they have experienced from projects that they have carried out over the past 3 years. As a result of this analysis, CEPA/PB felt that the estimates provided by the GT PRO tool were too low and recommended that an adjustment factor should be applied to the GT Pro estimate in order to reflect the actual EPC costs they have experienced.

. CEPA/PB used an adjustment factor of 3.8% based on recent relevant projects PB has completed.

. The data used in calculating this adjustment factor was presented to the RAs but due to confidentiality the derivation of the adjustment factor cannot be included in this paper. The RAs are satisfied with the approach taken by CEPA/PB in determining the adjustment factor of 3.8%.

The EPC Cost estimates provided by CEPA/PB are detailed in Table 5.1 below. These figures include a 3.8% uplift.

| Plant Type | Fuel Type | Average Lifetime Output (MW) | EPC Cost (€m) |
|---|---|---|---|
| **1 x Alstom GT13E2** | Distillate | 190.1 | **89.4** |
| | Gas | 193.6 | **89.4** |
| **1 x SGT5-2000E** | Distillate | 166.6 | **80.0** |
| | Gas | 166.8 | **80.1** |
| **4 x GE LM6000 PC Sprint** | Distillate | 193.3 | **130.2** |
| | Gas | 194.5 | **133.9** |
| **3 x P & W FT8 Swift Pac 60 (wet)** | Distillate | 183.6 | **117.5** |
| | Gas | 184.9 | **118.0** |

**Table 5.1** – *Summary of Proposed EPC costs for Short Listed Plants*

Table 5.2 details the assumptions used in the determination of the above costs.

| Area of Assumption | Distillate | Gas |
|---|---|---|
| Water injection : Fuel Mass Flow Ratio | 1:1 | 1:1 |
| Average output degradation over the economic lifetime | 2.5% | 2.0% |
| Average lifetime inlet pressure draught loss | 6 mbar | 6 mbar |
| Average efficiency degradation over the economic lifetime | 1.25% | 1.0% |

**Table 5.2** – *Assumptions used in Determination of EPC costs*

Further information on the EPC costs and assumptions used can be found in the CEPA/PB report in section 3.5

## 5.6 PROPOSED TECHNOLOGY OPTION

In line with previous years, a screening curve analysis was carried out for the four short listed options for both distillate and gas. The analysis compares the annualised specific costs of each short-listed option for varying utilisation factors. The costs used in the screening curve include the EPC costs discussed above as well as the investment and recurring cost as discussed in Section 6 and Section 7 of this paper. The variable costs that would be bid into the energy market are also considered in the screening curve analysis. The screening curve analysis graphs are shown below for both gas and distillate.

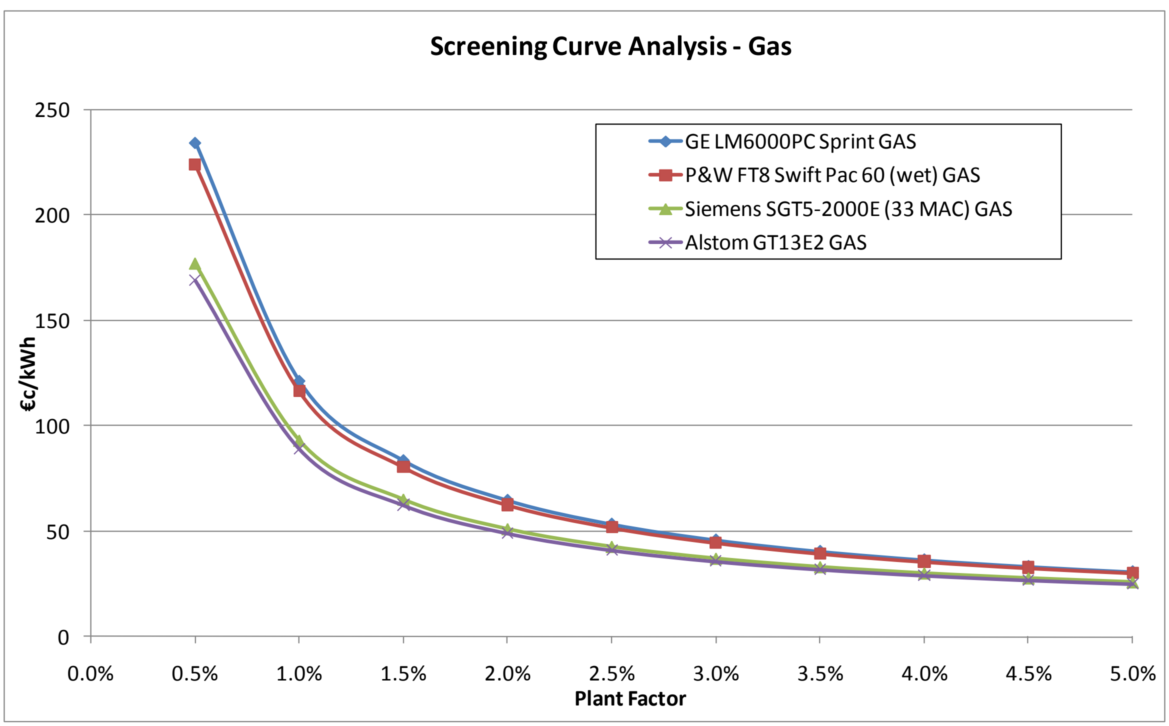


**Figure 5.1** – *Screening Curve Analysis for Gas*

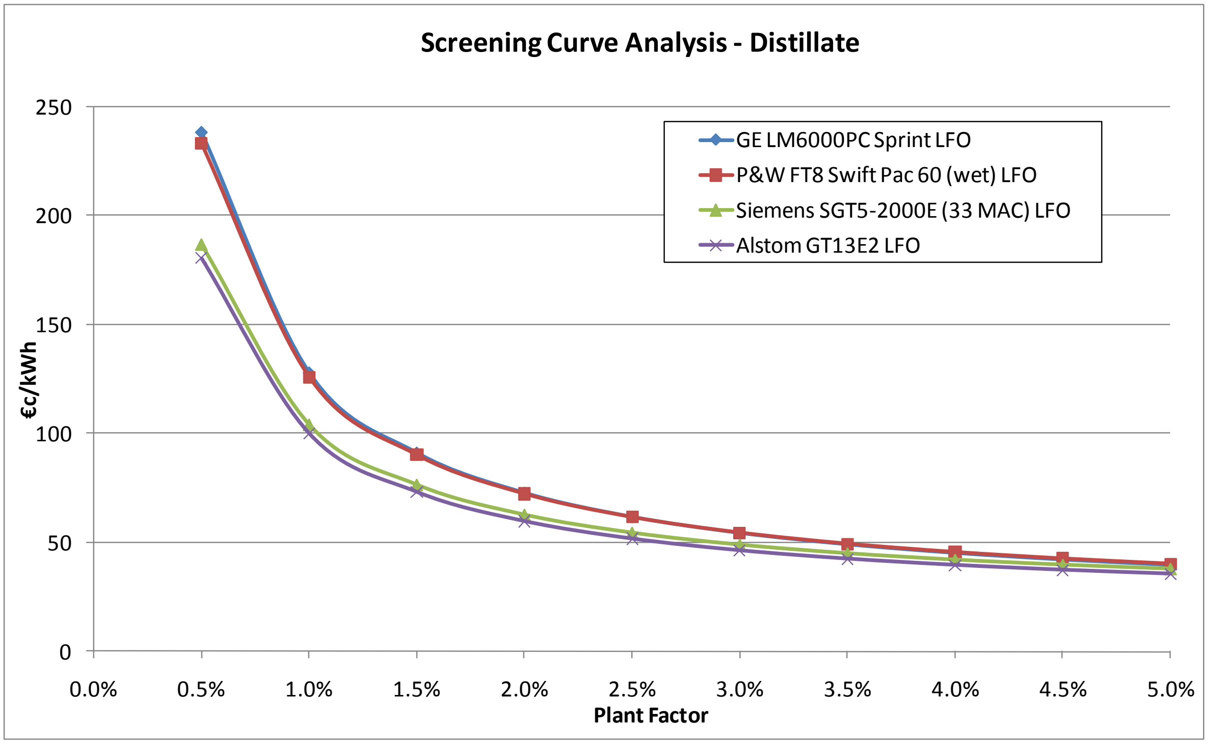


**Figure 5.2** – *Screening Curve Analysis for Distillate*

Based on the screening curve analysis, the Alstom GT13E2 and Siemens SGT5-2000E are much more favourable than the GE LM6000 PC Sprint and P&W FT8 Swift Pac 60 options.

The two plant were then compared to determine the BNE plant for 2010. Based on the plant factor range of 0.0% to 5.0% used in the screening curve analysis, for every point in the range, the costs associated with the Alstom GT13E2 are lower that the Siemens SGT5-2000E costs. Therefore, the recommendation for the technology for the BNE Peaker 2010 is the Alstom GT13E2. It should be noted that the Alstom GT13E2 was the best option for both distillate and gas fuelling options in the screening curve analysis.

Further information on the screening curve and recommendation can be found in the CEPA/PB report in section 3.6. In addition, the key assumptions used in the selection of the technology option are also detailed.

**The Proposed Technology Option for the BNE Peaker 2010 is the Alstom GT13E2**

# 6 INVESTMENT COSTS

This section details the key cost areas that make up the capital costs of the BNE Peaker. The key cost areas given consideration are:

- EPC Costs
- Site Procurement costs
- Electrical Connection costs
- Gas and Make-up Water Connection costs
- Owner's Contingency
- Financing, Interest During Construction (IDC) and Construction Insurance
- Up front costs for fuel working capital
- Other non-EPC costs
- Market Accession and Participation Fees

These are discussed in the following sections of this paper. Further details are available in Section 4.3 of the CEPA/PB report.

## 6.1 EPC COSTS

The EPC costs are covered in section 5.5 above. Table 6.1 summaries the proposed EPC costs for the Alstom GT13E2 for each fuel type. The same EPC cost is assumed regardless of location of the plant. It should be noted that the costs below assume the period to build the plant is 18 months with a lead time for the transformer of 12 months being on the critical path.

| Plant Type | Fuel Type | Average Lifetime Output (MW) | EPC Cost (€m) |
|---|---|---|---|
| 1 x Alstom GT13E2 | Distillate | 190.1 | €89,397,000 |
| | Gas | 193.6 | €89,421,000 |

**Table 6.1** – *Summary of Proposed EPC costs for* Alstom GT13E2

## 6.2 SITE PROCUREMENT COSTS

The RAs in conjunction with CEPA/PB considered options for a suitable location in both Northern Ireland and the Republic of Ireland. Discussions were also held with the TSOs on the areas that could be considered for the BNE Peaker for 2010. The area of land needed is estimated to be 20,600m$^2$.

For Northern Ireland, the preferred option considered was the Belfast West site. This land has been cleared of the original power station and is part of the land-bank area reserved by NIAUR for generation construction in the future.

For the Republic of Ireland, land costs were sourced for locations in the south east and midlands as several generators have registered interest to locate in this region.

CEPA/PB sourced indicative costs of land from a property market expert for both Northern Ireland and the Republic of Ireland. These costs are detailed in the table below. Further details are available in Section 4.3.2 of the CEPA/PB report.

Due to the significant movements in the economy over the last year, the value of land has reduced when compared with estimates used in the 2009 BNE Calculations. The reduction is in the region of 63% (see Appendix 2). An independent expert assessment was carried out on current land values to advise the RAs for the purposes of this study.

| Location | Required area ($m^2$) | Site Costs (€) |
|---|---|---|
| Northern Ireland | 20,600 | 1,425,288 |
| Republic of Ireland | 20,600 | 1,527,095 |

**Table 6.2** – *Summary of Site Procurement Costs*

## 6.3 ELECTRICAL CONNECTION COSTS

The RAs worked closely with the TSOs in determining the electrical connection costs. For Northern Ireland, it was assumed that a 110kV connection would be used for the Belfast West site. In the Republic of Ireland, it was assumed that the connection would be at 220kV and require a 4km connection.

The costs for each site are summarised in the table below:

| Location | Electrical Interconnection Cost (€) |
|---|---|
| Northern Ireland | 7,400,000 |
| Republic of Ireland | 5,676,000 |

**Table 6.3** – *Summary of Electrical Connection Costs*

## 6.4 GAS AND MAKE-UP WATER CONNECTION COSTS

CEPA/PB provided the following estimates for Gas and Water Charges for each location.

| Location | Cost of water connection (€) | Cost of gas connection (€) |
|---|---|---|
| Northern Ireland | 0 | 1,690,000 |
| Republic of Ireland | 400,000 | 3,380,000 |

**Table 6.4** – *Summary of Gas and Make up Water Connection Costs*

The assumptions used for Northern Ireland was that minimal water connection costs would be incurred due to the proximity of the water mains to the proposed site. For gas a 1km gas pipeline to Belfast West was assumed.

The assumptions used for the Republic of Ireland were an installed 1km water pipeline, 4 inches in diameter and a 2km gas pipeline to the site.

## 6.5 OWNER'S CONTINGENCY

CEPA/PB has recommended an owner's contingency value of 5.2% of the EPC costs. This is based on their project experience. Therefore in the case of the Alstom GT13E2 the estimated Owners Contingency is detailed in table 6.5.

This is a significant increase from the assumption used in 2009 where the contingency level assumed was in the region of 1.6% and reflects PB's experience in recent years.

| Plant Type | Fuel Type | Owner's Contingency Cost (€m) |
|---|---|---|
| 1 x Alston GT13E2 | Distillate | €4,648,648 |
| | Gas | €4,649,908 |

**Table 6.5** – *Summary of Owners Contingency costs for* Alstom GT13E2

## 6.6 FINANCING, INTEREST DURING CONSTRUCTION (IDC) AND CONSTRUCTION INSURANCE

Similar to the Owner's Contingency, CEPA/PB have estimated the costs associated with Financing and Construction Insurance as a percentage of the EPC costs while the Interest During Construction (IDC) estimate is based on their project experience and are calculated on a jurisdictional basis. These are summarised in table 6.6 below.

| | Total Cost for Distillate (€) | Total Cost for Gas (€) |
|---|---|---|
| Financing | 1,788,000 | 1,788,000 |
| IDC (NI) | 1,821,000 | 1,849,000 |
| IDC (ROI) | 1,727,000 | 1,781,000 |
| Construction Insurance | 805,000 | 805,000 |

***Table 6.6** – Summary of Financing, IDC and Construction Insurance costs for Alstom GT13E2*

## 6.7 INITIAL FUEL WORKING CAPITAL

Another area of costs identified by CEPA/PB was the Fuel Working Capital for the initial fill. This is required for a gas plant to adhere with the secondary fuel obligation in the Republic of Ireland. The fuel security code for

Northern Ireland is currently under review therefore it is assumed that the above obligation would be applicable in either jurisdiction.

CEPA/PB have estimated an initial fuel storage fill cost of €2.7m. This is based on a requirement to run for 72 hours full load and an oil price of US$65/barrel.

| Location | Fuel Cost (€) |
|---|---|
| Working Capital for Fuel (either jurisdiction) | 2,665,000 |

**Table 6.7** – *Summary of Fuel Working Capital*

Note that there are other initial working capital assumptions that are considered in the final calculations in section 9.

## 6.8 OTHER NON-EPC COSTS

CEPA/PB grouped the remaining costs together to allow a logical comparison of the data they held on their project experiences. The cost areas included under 'Other Non-EPC Costs' include EIA, legal, owner's general and administration, owner's engineer, start-up utilities, commissioning, O & M mobilisation, spare parts and working capital. Based on CEPA/PB's experience, the Other Non-EPC Costs equates to 9.0% of the EPC Costs.

Similar to the process used for determining the adjustment factor to be applied to the EPC costs as mentioned in section 5.5 above, the data used in calculating the percentage allocation for Other Non-EPC Costs was presented to the RAs but due to confidentiality, the derivation of this percentage allocation cannot be included in this paper. The RAs are satisfied with the approach taken by CEPA/PB in determining the Other Non-EPC Costs.

| | Proportion of EPC | Total Cost for Distillate (€) | Total Cost for Gas (€) |
|---|---|---|---|
| Other Non-EPC Costs | 9.0% | 8,046,000 | 8,048,000 |

**Table 6.8** – *Summary Other Non-EPC costs for Alstom* GT13E2

## 6.9 MARKET ACCESSION AND PARTICIPATION FEES

Similar to 2009, the required fees to enter the SEM were considered. Based on the current tariffs, these will cost €5,000 and although small are included for completeness. These charges are payable to the market operator, SEMO.

## 6.10 SUMMARY OF INVESTMENT COSTS

The table below summarises all the investment cost for the Alstom GT13E2 for each jurisdiction and for each fuel type.

| Cost Item | RoI Dual Fuelled | RoI Distillate | N Ireland Dual Fuelled | N Ireland Distillate |
|---|---|---|---|---|
| EPC Costs | 89,421,000 | 89,397,000 | 89,421,000 | 89,397,000 |
| Site Procurement | 1,527,000 | 1,527,000 | 1,425,000 | 1,425,000 |
| Electrical connection Costs | 5,676,000 | 5,676,000 | 7,400,000 | 7,400,000 |
| Gas connection | 3,380,000 | - | 1,690,000 | - |
| Water connection | 400,000 | 400,000 | 0 | 0 |
| Owners Contingency | 4,650,000 | 4,649,000 | 4,650,000 | 4,649,000 |
| Financing Costs | 1,788,000 | 1,788,000 | 1,788,000 | 1,788,000 |
| Interest During Construction | 1,781,000 | 1,727,000 | 1,849,000 | 1,821,000 |
| Construction Insurance | 805,000 | 805,000 | 805,000 | 805,000 |
| Initial Fuel working capital | 2,665,000 | 2,665,000 | 2,665,000 | 2,665,000 |
| Other non EPC Costs | 8,048,000 | 8,046,000 | 8,048,000 | 8,046,000 |
| Accession & Participation Fees | 5,000 | 5,000 | 5,000 | 5,000 |
| **Total** | **120,146,000** | **116,684,000** | **119,747,000** | **118,000,000** |

**Table 6.9** – *Summary of Investment Costs for Alstom* GT13E2

It should be noted that at this stage the options using Gas are the more expensive options mainly due to the Gas connection costs. With the secondary fuel obligation, the distillate storage facilities also need to be considered.

# 7 RECURRING COSTS ESTIMATE

As well as the Investment Costs, the rational investor will need to consider the recurring costs incurred on an annual basis. The main areas of recurring costs identified are:

- Market Operator charges
- Transmission TUoS charges
- Gas Transmission Charges
- Operation and Maintenance Costs
- Insurance
- Business Rates
- Fuel working capital

Each of these areas is discussed in section 4.4 of the CEPA/PB report including the assumptions used in determining the cost estimates.

In relation to the Market Operator Charges, TuOS charges and Gas Transmission charges, the current published tariffs were used as sources. If updated tariffs relating to 2010 are available ahead of a decision on the cost of the BNE Peaker for 2010, the values in the table below will be adjusted accordingly to reflect these.

| Cost Item | RoI Dual Fuelled | RoI Distillate | N Ireland Dual Fuelled | N Ireland Distillate |
|---|---|---|---|---|
| Transmission & Market operator charges | 1,074,000 | 1,056,000 | 816,000 | 801,000 |
| Gas Transmission Charges | 880,000 | - | 809,000 | - |
| Operation and maintenance costs | 1,675,000 | 1,650,000 | 1,675,000 | 1,650,000 |
| Insurance | 1,431,000 | 1,430,000 | 1,431,000 | 1,430,000 |
| Business Rates | 1,516,000 | 1,489,000 | 586,000 | 578,000 |
| Fuel working capital | 181,000 | 181,000 | 190,000 | 190,000 |
| **Total** | **6,757,000** | **5,806,000** | **5,507,000** | **4,649,000** |

**Table 7.1** – *Summary of Recurring Costs for BNE Peaker for 2010*

As was the case with the Investment Costs, the recurring costs for Gas are also higher than the Distillate options.

# 8 ECONOMIC & FINANCIAL PARAMETERS

## 8.1 INTRODUCTION

As with previous years, a key activity in the calculation of the BNE Peaker is the determination of WACC. CEPA/PB carried out an extensive investigation of the building blocks of WACC. Their analysis is detailed in Section 5 and Annex 3 of the CEPA/PB paper. CEPA/PB provided a range within which they believe the appropriate WACC should lie. The RAs attended a meeting that CEPA held with their banking contacts on the financing costs of similar types of investment in the UK and Ireland. The discussions and information shared at these meetings was a useful cross check to the CEPA analysis and validated the assumptions used.

## 8.2 NATURE OF THE BNE INVESTMENT

As part of the CEPA/PB analysis, a number of assumptions were discussed and agreed with the RAs on the nature of the BNE investment. These are discussed in more detail in section 5.1.2 of the CEPA/PB report. The main assumptions are detailed below.

| Area | Assumption |
|---|---|
| **Type of Investor** | It is assumed that the BNE investor is likely to be an integrated utility seeking to raise funding at the corporate level for the peaking plant investment project in the forthcoming year.<br><br>In addition, it is assumed that the BNE is a green-field investment with no existing assets and associated financing costs. |
| **Plant Life** | The economic life of the project has been taken as 20 years. Previously 15 years was used, with some consideration of a residual value, but 20 years is thought to be more appropriate. There has been a trend for CCGT plants to be economically evaluated over 30 years and even 35 years as opposed to the historical 25 years. Similarly, a trend for the economic life of peaking SCGT is moving from 15 years to 20 years<br><br>In the Decision Paper for the 2009 BNE Peaker Calculations, the SEM Committee indicated their intention to investigate the issue of residual value and cost components in future exercises of estimating the cost of a BNE Peaker. As this was raised after the consultation paper and at the time of the decision paper, the RAs decided not to introduce it for the 2009 pot but flagged its consideration for 2010.<br><br>PB has advised the RAs that the life time of a plant can typically be longer than 15 years, and CEPA suggested that the economic life of the plant should be represented in the calculations.<br><br>Considering in previous years a 15 year economic life with and unspecified residual value was assumed, it is appropriate to move to a 20 year economic life with no residual value. |

| | |
|---|---|
| **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.<br><br>It is also assumed that the investor would seek to maximise the debt/equity ratio, but that in the current financial markets this would mean a gearing ratio of 60%. This is the same level of gearing as was used in the 2009 calculations. |
| **Credit Quality** | It is assumed that a BNE investor has an investment grade credit rating in the range BBB to A . This is because a sub-investment grade entity would not be competitive for this type of project and indeed may struggle to raise the necessary funding. |

**Table 8.1** – *Summary of Assumptions on the Nature of Investment*

## 8.3 WACC PROPOSALS

Annex 3 of the CEPA report provides a comprehensive summary of the assumptions used by CEPA/PB in their recommendation of the WACC to be used for the BNE Peaker for 2010. In summary, CEPA/PB recommended the appropriate range for the real pre-tax WACC for the BNE peaking plant is 5.85% - 7.75% in the Republic of Ireland and 6.25% - 8.0% in the UK.

A summary of the WACC parameters provided by CEPA is detailed in table 8.2 below. The 2009 WACC values have been included to allow a comparison

| | | RoI | | | UK | |
|---|---|---|---|---|---|---|
| **Element** | **2009** | **2010 Low** | **2010 High** | **2009** | **2010 Low** | **2010 High** |
| Risk-free rate | 2.11% | 1.50% | 2.25% | 2.51% | 1.50% | 2.00% |
| Debt premium | 2.25% | 3.00% | 4.00% | 2.25% | 2.50% | 3.50% |
| **Cost of debt** | **4.36%** | **4.50%** | **6.25%** | **4.76%** | **4.00%** | **5.50%** |
| ERP | 5.50% | 4.50% | 5.00% | 5.50% | 4.50% | 5.00% |
| Equity beta | 1.39 | 1.20 | 1.3 | 1.25 | 1.2 | 1.3 |
| **Post-tax cost of equity** | **9.75%** | **6.90%** | **8.75%** | **9.38%** | **6.90%** | **8.50%** |
| Taxation | 12.5% | 12.5% | 12.5% | 28.0% | 28.0% | 28.0% |
| Pre-tax cost of equity | 11.15% | 7.90% | 10.00% | 13.03% | 9.60% | 12.00% |
| Gearing | 60.0% | 60.0% | 60.0% | 60.0% | 60.0% | 60.0% |
| **Pre-tax WACC** | **7.07%** | **5.85%** | **7.75%** | **8.07%** | **6.25%** | **8.00%** |

**Table 8.2** – *Summary of WACC parameters recommended by CEPA/PB*

The RAs used the recommended ranges in their determination of the suitable WACC values to be used for the BNE Peaker for 2010. The values to be used are the mid point of the ranges recommended by CEPA/PB. The proposed WACC values to be used for the BNE Peaker for 2010 are detailed in Table 8.3 below.

| Element | 2010 RoI | 2010 UK |
|---|---|---|
| Risk-free rate | 1.88% | 1.75% |
| Debt premium | 3.5% | 3.0% |
| **Cost of debt** | **5.38%** | **4.75%** |
| ERP | 4.75% | 4.75% |
| Equity beta | 1.25 | 1.25 |
| **Post-tax cost of equity** | **7.81%** | **7.69%** |
| Taxation | 12.5% | 28% |
| Pre-tax cost of equity | 8.93% | 10.68% |
| Gearing | 60.0% | 60.0% |
| **Pre-tax WACC** | **6.80%** | **7.13%** |

**Table 8.3** – *Proposed WACC values to be used for the BNE Peaker for 2010*

# 9 PROPOSED BEST NEW ENTRANT PEAKER FOR 2010

## 9.1 SUMMARY OF COSTS

Based on the analysis carried out and detailed in Section 6 to Section 8 of this paper, the RAs have summarised the results of the annualised costs for the Alstom GT13E2 for each jurisdiction and fuel type. These are summarised in table 9.1 below.

| Cost Item (000's) | RoI Dual Fuelled | RoI Distillate | N Ireland Dual Fuelled | N Ireland Distillate |
|---|---|---|---|---|
| Investment Cost (excl Fuel Working Capital | 117,481 | 114,019 | 117,082 | 115,335 |
| Initial Working Capital (including Fuel) | 4,978 | 5,559 | 4,769 | 5,366 |
| Residual Value for Land & Fuel | - 1,124 | - 1,124 | - 1,033 | - 1,033 |
| **Total Capital Costs** | **121,335** | **118,454** | **120,819** | **119,668** |
| WACC | 6.80% | 6.80% | 7.13% | 7.13% |
| Plant Life (years) | 20 | 20 | 20 | 20 |
| Annualised Capex | 11,276 | 11,008 | 11,520 | 11,410 |
| Recurring Cost | 6,913 | 5,961 | 5,639 | 4,779 |
| **Total Annual Cost** | **18,189** | **16,969** | **17,159** | **16,189** |
| Capacity (MW) | 193.6 | 190.1 | 193.6 | 190.1 |
| **Annualised Cost per kW** | **93.95** | **89.25** | **88.63** | **85.16** |

**Table 9.1** – *Annualised costs for BNE Peaker for 2010*

## 9.2 RECOMMENDATION FOR BEST NEW ENTRANT PEAKER FOR 2010

Based on the above figures, the Distillate option is more economical than the Gas option and overall the Distillate plant in Northern Ireland is the preferred option.

**The Proposed Best New Entrant Peaker for 2010 is the Alstom GT13E2, located in Northern Ireland and uses Distillate fuel**

## 9.3 IMPACT OF FUEL TYPES ON BNE SELECTION

As part of the 2010 BNE consultation process, the RAs decided to consider both gas and distillate technology as options for the selection of the BNE plant. This was largely in response to the various comments received as part of the BNE decision in 2009 and representation made by Bord Gais Networks (BGN) and Gaslink.

The RAs met with Bord Gais Networks to gain an understanding of the short term products available and the tradability of products in the secondary market, where Bord Gais presented the short term gas capacity products available in the Republic of Ireland and an interruptible product in Northern Ireland. During these discussions BGN also indicated that currently there are no capacity issues on the island.

The RAs note that a variety of short term capacity products from a variety of sources are available in the Republic of Ireland, and a range of short term products as required by EU directive 1775 are also available. However a similar range of products on an uninterruptible/firm basis are currently not available in Northern Ireland, but are planned for delivery under the Common Arrangements for Gas (CAG).

This inconsistency in the two jurisdictions does create an issue of equity in treatment of generators located in both jurisdictions that requires further consideration. Furthermore, the RAs wish to deliberate on this matter in a holistic manner taking into consideration issues such as the bidding principles and the energy market. The RAs are therefore of the view these matters should be included for further consideration in the Medium Term Review of Capacity Payment Mechanism.

None the less, based on the information provided by Bord Gais Networks, the RAs did consider both gas and distillate plants in the selection of a BNE peaking plant. As seen in table 9.1, from the analysis carried out, the distillate option is the more economical and therefore the recommended option for 2010.

## 10 INFRA MARGINAL RENT

In order to assess the infra marginal rent a BNE peaking plant might expect to receive from the energy market, assumptions must be made about the future value of SMP realised in the trading periods in which the peaking plant is assumed to be active in the energy market. It is assumed that, as a profit maximising entity, the BNE peaking plant will operate in all those trading periods that provide it with infra marginal rent .

The approach to the derivation of the estimated inframarginal rent for the BNE peaker for 2010 replicates the process used in previous years (2007, 2008 and 2009). The approach used is to complete two plexos runs, one with the BNE peaking plant and all its true characteristics and one without. A unit commitment schedule is derived for the BNE peaking plant from the first plexos run and the actual infra marginal rent calculation is then derived using the original SMP estimations from the plexos run without the BNE peaking plant included.

To calculate the infra-marginal rent, the most up-to-date SEM Plexos model was used. This model is identical to that used in the recent Directed Contracts parameter calculations. This model has been published by the RAs. Twenty five full year half hourly simulations of the SEM in 2010 were run, in which forced outage patterns were randomly generated[7] from one iteration to the next to give a spread of system margin scenarios across the year.

It was observed the Alstom GT13E2 plant was not scheduled at all in any of the twenty five iterations. On the basis of this analysis, it is assumed that there will be zero infra-marginal rent.

[7] While forced outage patterns were randomised, all other data remained constant across the iterations (scheduled outage patterns, demand, wind output etc).

## 11 ANCILLARY SERVICES

For the calculation of the Ancillary Services (AS) for the BNE peaker for 2010, the RAs have used the criteria as documented in the consultation paper 'Harmonised Ancillary Services & Other System Charges Rates Consultation' published on 8th June 2009 (SEM-09-062)[8].

As the timelines for Ancillary Services harmonisation to be agreed falls in 2010, the RAs deemed it as prudent to use the harmonised rules to calculate the AS revenue the BNE peaker for 2010 may achieve. It should be noted that any changes as a result of the AS Harmonisation Consultation Paper will be fed into the BNE peaker for 2010 Decision Paper.

The RAs worked closely with the TSOs in calculating the appropriate costs for Ancillary Services under the new propose criteria and formulae. The assumptions used in the Ancillary Service Calculations are:

- Unit size is 190.1MW
- Run hours is 5%
- Load factor is 60%

The estimated value of Ancillary Services that the BNE peaker for 2010 would achieve is €960.383. This equates to €5.05 per kW for a 190.1MW unit. Table 11.1 shows a breakdown of the calculation used.

| Cost Item | Annual Availability (Half Hour) | Annual Hourly Rate €/MWh | Annual Payment € |
|---|---|---|---|
| Primary Operating Reserve | 21,900 | 2.22 | 24,309 |
| Secondary Operating Reserve | 59,586 | 2.13 | 63,459 |
| Tertiary Operating Reserve 1 | 66,611 | 1.76 | 58,618 |
| Tertiary Operating Reserve 2 | 66,611 | 0.88 | 29,309 |
| Replacement Reserve Unit Synchronised | 66,611 | 0.2 | 6,661 |
| Replacement Reserve Unit De-Synchronised | 2,997,497 | 0.51 | 764,362 |
| Reactive Power (Leading) | 52,560 | 0.13 | 6,833 |
| Reactive Power (Lagging) | 52,560 | 0.13 | 6,833 |
| **Total** | | | **960,383** |

**Table 11.1** – *Summary of Ancillary Services Costs for 2010*

[8] http://www.allislandproject.org/en/transmission.aspx?article=422a7c94-d5bf-4bf3-8651-0f363f795366

# 12 INDICATIVE BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2010

The table below shows a summary of the costs and the final annualised cost of the BNE Peaker for 2010. This includes the deduction of any revenues obtained from Inframarginal Rent or Ancillary Services.

| Cost Item (000's) | N Ireland Distillate |
|---|---|
| Annualised Cost per kW | 85.16 |
| Ancillary Services | 5.05 |
| Inframarginal Rent | - |
| **BNE Cost per kW** | **80.11** |

**Table 12.1** – *Final costs for BNE Peaker for 2010*

# 13 CAPACITY REQUIREMENT FOR 2010

## 13.1 INTRODUCTION

The methodology used for calculating the Capacity Requirement for 2010 is the same as that used in previous year's calculations. The RAs have included the Capacity Requirement Calculation as a possible work stream in the CPM Medium Term review with the intention of reviewing the process in order to address concerns raised by participants relating to the perceived the level of transparency.

This section details the individual components and calculations that have been carried out for the quantification of the 2010 Capacity Requirement.

## 13.2 BACKGROUND TO CALCULATION OF CAPACITY REQUIREMENT PROCESS

The Capacity Requirement quantification process was consulted on in August 2006 under 'Methodology for the Determination of the Capacity Requirement for the Capacity Payment Mechanism' (AIP/SEM/111/06). This was a comprehensive consultation which took place following an initial consultation on the Capacity Payments Mechanism in March 2006 entitled 'The Capacity Payment Mechanism and Associated Input Parameters' (AIP/SEM/15/06).

A Decision Paper was published in February 2007 which set out the RAs decisions on the contents of the August 2006 Consultation Paper. This Decision Paper laid out the key methodology and individual data point assumptions. These parameters were used in calculating the 2007, 2008 and 2009 Capacity Requirement.

## 13.3 PARAMETER SETTINGS FOR CAPACITY REQUIREMENT FOR 2010

As anticipated in the initial consultation and decision papers, the same parameter settings have been used in the calculation for the 2010 Capacity Requirement. The following sections describe further each of these parameters.

### 13.3.1 GENERATION SECURITY STANDARD (GSS)

In AIP/SEM/111/06 the RAs stated that a single GSS for the entire island would be applied following detailed research by the TSOs in March 2007. This research was presented to the AIP Steering Group in May 2007 and the RAs subsequently decided on a GSS of 8 hours Loss of Load Expectation per annum. The GSS decided upon during the early part of 2007 following this research has been retained by RAs for the 2010 calculation.

### 13.3.2 DEMAND FORECAST

Considering the recent changes in demand as a result of the economic downturn, the RAs have worked closely with both TSOs in determining a suitable forecast for 2010. Recent demand trends and economic forecasts were used in the analysis. As a result, the forecasted demand, used in the Capacity Requirement Calculation, as a percentage of the previous year for each jurisdiction was determined to be as follows:

| | 2009 Forecasted Total Energy Requirement | 2010 Forecasted Total Energy Requirement |
|---|---|---|
| **Republic of Ireland** | -3.8% | -0.9% |
| **Northern Ireland** | -3.6% | -0.5% |

**Table 13.1** – *Forecasted Demand of Total Energy Requirement*

Note that the forecasts in the above table are negative values reflecting the expected drop in demand.

In light of the significant down turn in growth and energy demand EirGrid provided the following key points in relation to the above forecasts.

- Since the publication of GAR 2009-2015 in December 2009, the economic situation has deteriorated and it is now markedly different from economic forecasts made in 2008. This has also coincided with a reduction in electricity demand since January 2009.
- Historically there has been a reasonable correlation between economic growth and increases in electricity demand. Previous demand forecasts have been made based on economic forecasts by economists such as the ESRI. In recent times though, the correlation between economic growth and electricity demand has changed as growth in the economy has transitioned to less energy intensive sectors.
- EirGrid carried out a comparison of the demand trend for 2009 with the previous 2 years on a monthly basis. Demand levels have dropped below even the same 5 month period of 2007. Demand is down in the region of 5% on the same period (5 months) last year. See the graph below for further details

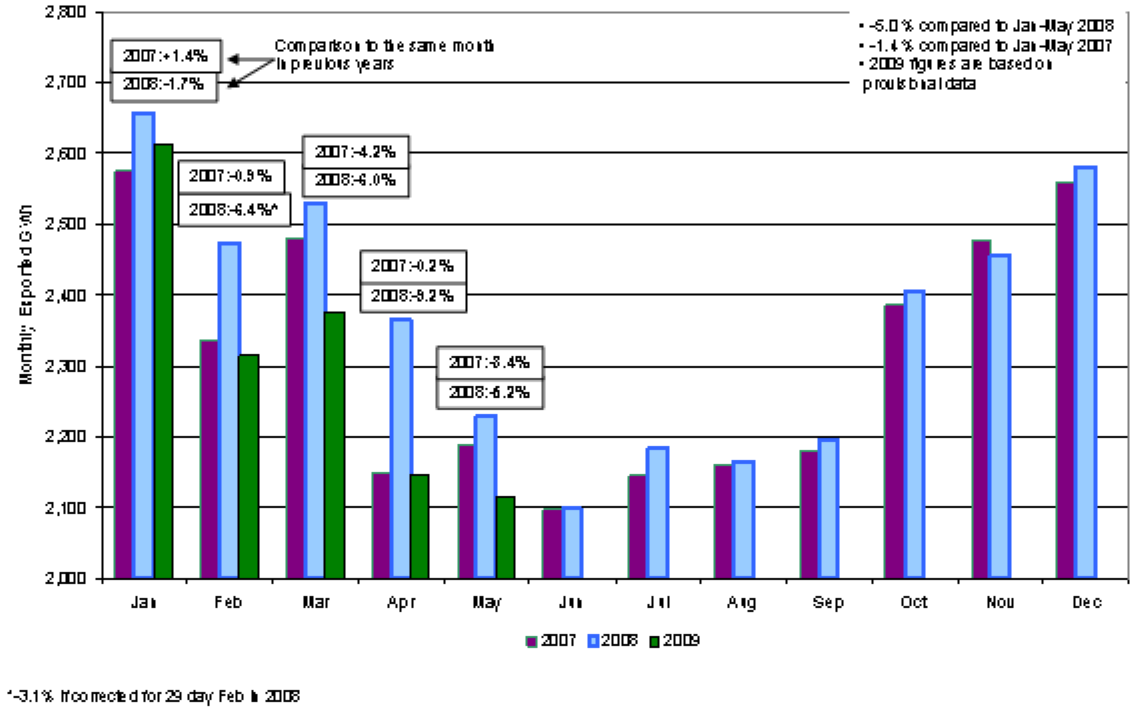


**Figure 13.1** – *Current Demand Comparison for RoI*

- A number of demand scenarios have been developed by EirGrid to forecast the extent of the downturn in demand and to anticipate future demand recovery. The forecasting considers the latest short-term economic forecasts from the Central Bank's latest quarterly bulletin[9], The CSO's latest estimate of the economic outturn of 2008[10] and the latest ESRI commentary on the economy[11]. Medium-Long term forecasting is based on average forecasts from the ESRI's most recent Medium Term Review[12].

- For the purposes of calculating the Capacity Requirement, a TER reduction of 3.8% is forecasted for 2009. This is estimated with consideration of the observed export data described above and the most up to date economic forecasts. There is a further reduction of 0.9% in 2010. Eirgrid assume here that the bulk of demand reduction has occurred in 2009 but the forecasted further contraction in the economy results in a further 1% drop in electricity sales. This corresponds to a 0.9% drop in TER. It is then assumed that the economy begins to recover by 2011.

[9] https://www.centralbank.ie/data/QrtBullFiles/CB-Q2-09-Econ-Comm.pdf

[10] http://www.cso.ie/releasespublications/documents/economy/current/qna.pdf

[11] http://www.esri.ie/publications/latest_publications/view/index.xml?id=2738

[12] http://www.esri.ie/UserFiles/publications/20080515155545/MTR11.pdf

SONI provided the following key points in relation to the above forecasts.

- On the assumption that economic factors influence electricity demand it would also seem logical to account for these unprecedented economic conditions in the forecast of future Peak Demand and Energy Production.

- On a GDP basis the UK economy is predicted to contract by 3% in 2009 before experiencing a modest recovery in 2010. The main areas of the NI economy which have suffered include the retail sector, the manufacturing sector, which is experiencing a huge slowdown, and the construction industry

- In the "First Trust Bank Economic Outlook & Business Review, March 2009" it is forecast that the NI economy will contract with the rest of the UK economy during 2009 before experiencing a similar recovery during 2010. As of March 2009 GDP in NI is forecast by the First Trust Bank to fall by 1.5% in 2009 before steadying out to 0.0% in 2010.

- The "Ulster Bank NI Quarterly Review" published in February 2009 stated "manufacturing output remained flat in Q3 2008 but is expected to decline sharply in Q4 2008 and in 2009." This would align with the trends in Peak Demand and Energy Production that have been seen since October 2008.

- The actual data for the first 3 months of 2009 was compared with the adjusted 2008 figures for the same 3 months. It was observed that in January there was an increase of 2.9% on the adjusted 2008 figure, in February there was an increase of 2.7% on the adjusted 2008 figure and an even further reduction in this month on month % increase in March to 0.8% as seen below.

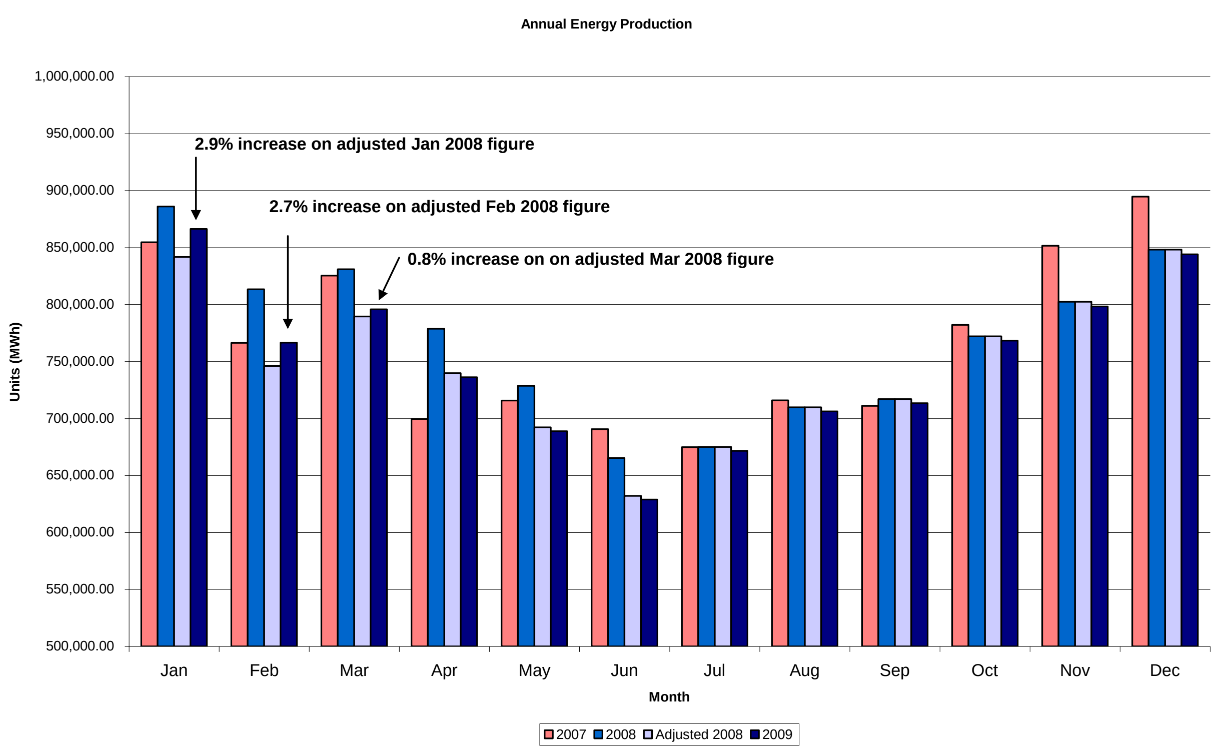

**Figure 13.2** – *Current Demand Comparison for NI*

- Following discussions with the RAs, the forecasts used by SONI in calculating the Capacity Requirement assume that the NI economy does not recover as fast as hoped and actually falls deeper into recession throughout 2009 and 2010 causing recovery to be much later towards 2012. The forecast Annual Energy Production for 2009 will be approximately 3.6% lower than in 2008 given the expected fall in GDP. Furthermore in this scenario we consider the case that the economy has not yet bottomed out and further drops in economic output are experienced in 2010, leading to another fall in Annual Energy Production in 2010 before experiencing a very small increase in 2011.

Considering the unprecedented times, the RAs are minded to revisit the forecasts above with the TSOs to ensure that they still reflect the actual demand trend. This activity may take place during July 2009 ahead of any decision on the Capacity Requirement for 2010.

For the 2010 Capacity Requirement calculation, the TSOs were asked to provide half-hourly demand forecast profiles. Care was exercised to ensure that the jurisdictional traces were harmonised (i.e. based on the same reference year, 2008, and day-shifted to align on a day-by-day basis). The RAs assisted in combining these jurisdictional load traces into a single, all-island demand trace for input to the CREEP calculation engine (described below).

### 13.3.3 GENERATION CAPACITY

Similar to the 2009 Capacity Requirement calculations, the generation capacity data was already collected as part of the Directed Contracts process that took place in early 2009. As such this data was sourced from the Directed Contracts database, with discussion with TSOs as needed in supplement.

### 13.3.4 SCHEDULED OUTAGES

In the Decision Paper AIP/SEM/07/13 it was decided that scheduled outages for thermal plant would be quantified based on the previous 5 years of unit set data, and that the CREEP algorithm would be permitted to efficiently schedule these outages during the calendar year. This process has been applied in formulating the scheduled outage inputs for each unit in the 2010 Capacity Requirement process.

### 13.3.5 FORCED OUTAGE PROBABILITIES

The Decision Paper AIP/SEM/07/13 sets out the RAs decision to set a target for Forced Outage Probabilities (FOP) to incentivise an improvement in plant performance above the historical levels. This value was calculated based on the observed improvements in plant performance following privatisation of the Northern Ireland portfolio in the 1990’s and was computed at 4.23%. The Decision Paper (AIP/SEM/07/13) makes it very clear that the computed value was to be used in calculations going forward. The RAs have carried this figure forward in its quantification of the 2010 Capacity Requirement. The RAs note that there are indications that availability has improved over the past year which suggests an improvement in the FOP rates. As highlighted earlier, the FOP is within the proposed scope of review of the CPM Medium Term review and the FOP value used in the Capacity Requirement calculation may be revisited.

### 13.3.6 TREATMENT OF WIND

The Decision Paper AIP/SEM/07/13 explains the RAs decision to treat wind as a netting trace against the load trace. This process, has been repeated in the 2010 process. Individual wind output traces were provided by the TSOs. The wind traces were built upon the same reference year and aligned on a day-by-day basis with the load traces described earlier.

### 13.3.7 CREEP CALCULATION PROCESS

Having collected together the various input data points, the TSOs ran the iterative CREEP[13] software process to calculate the 2010 Capacity Requirement.

The CREEP process has been described in AIP/SEM/111/06 and the subsequent decision to employ a 'perfect plant' method detailed in the Decision Paper AIP/SEM/07/13. The process is discussed in more detail below.

Once the input data has been assembled, the Capacity Requirement quantification process involves the following steps:

1. Use CREEP to calculate the Loss Of Load Expectation (LOLE) for 2010 that arises from the conventional market capacity, employed to meet the 2010 load trace with wind output netted from this trace.

2. Assuming this LOLE is below the target of 8 hours, add incremental block loads ('perfect plant') to the load trace and recalculate the LOLE.

3. Repeat Step 2 until the LOLE is exactly 8 hours for the year.

4. Note the quantity of block load used to obtain the 8 hour LOLE (referred to as BLOAD).

5. If in surplus, build a 'reference plant' with statistics based on the stack of generators (averaged capacity, SOD etc) .

[13] Note that for 2010, the TSOs used an updated 'CREEP' model referred to internally as 'Adcal'. The TSOs have carried out significant comparison testing of the CREEP and Adcal models and are content that the Adcal model provides equal-or-better solutions over the old CREEP model.

6. Add this plant to the stack and use CREEP to re-calculate LOLE, the LOLE will again decrease below the 8 hour mark.

7. Add some additional block load until the 8 hours is once again achieved. Note the amount of additional block load used in this step above the original BLOAD.

8. Divide the Capacity of the Reference plant by calculated in step 7 above. This represents the ratio of imperfect-to-perfect plant.

9. Multiply the ratio in step 8 by the original perfect surplus in step 4. This is the imperfect surplus.

10. Deduct the imperfect surplus from the total installed capacity used in Step 1, this is the conventional requirement.

11. Calculate the all-island Wind Capacity Credit based on the credit curve methodology used in the Generation Adequacy Report and the assumed installed capacity of Wind on the island.

12. Add the Wind Capacity Credit to the Step 10 conventional requirement, this is the final Capacity Requirement.

## 13.4 PROPOSED CAPACITY REQUIREMENT FOR 2010

As a result of the analysis carried out in conjunction with the TSOs, the RAs have determined that the Capacity Requirement for 2010 is **6,832MW.**

It is noted that this is a reduction of 7.1% from the Capacity Requirement for 2009. The main reason for the reduction in the Capacity Requirement is due to the reduction in the forecasted demand for 2010 as a result of the economic downturn.

**The Proposed Capacity Requirement for 2010 is 6,832MW**

# 14 INDICATIVE ANNUAL CAPACITY PAYMENT SUM FOR 2010

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement for 2010 as detailed in Sections 12 and 13 above, the Annual Capacity Payments Sum (ACPS) for 2010 is proposed to be €547.3M. The proposed figures are detailed in table 14.1 below.

| Year | BNE Peaker Cost (€/kW/yr ) | Capacity Requirement (MW) | ACPS (€) |
|---|---|---|---|
| **2010** | 80.11 | 6,832 | 547,315,942 |

**Table 14.1** – ACPS for the Trading Year 2010

**The Proposed Annual Capacity Payments Sum (ACPS) for 2010 is €547.3M**

## 15 VIEWS INVITED

Views are invited regarding any and all aspects of the proposals put forward in this Consultation Paper, and should be addressed (preferably via email) to both Kevin O'Neill at kevin.oneill@niaur.gov.uk and Priti Dave-Stack at pdave-stack@cer.ie by **5pm on Wednesday 29th July 2009**.

The SEMC intends to publish all comments received. Those respondents who would like certain sections of their responses to remain confidential should submit the relevant sections in an appendix marked confidential together with an explanation as to why the section should be treated as confidential.

# 16 APPENDIX 1 - ANNUAL CAPACITY PAYMENT SUM FOR 2007, 2008 & 2009

The annualised fixed cost of the BNE Peaker is multiplied by Capacity Requirement resulting in the Annual Capacity Payments Sum (ACPS). The ACPS for the Trading Years 2007, 2008 and 2009 are detailed in Table A1.1 below.

| Year | BNE Peaker Cost (€/kW/yr ) | Capacity Requirement (MW) | ACPS (€) |
|---|---|---|---|
| **2007** | 64.73 | 6,960 | 450,517,348 |
| **2008** | 79.77 | 7,211 | 575,221,470 |
| **2009** | 87.12 | 7,356 | 640,854,720 |

**Table A1.1** – ACPS for the Trading Years 2007, 2008 and 2009

# 17 APPENDIX 2 – COMPARISON WITH 2009 BNE PEAKING PLANT

The table below shows a comparison of the costs for the 2009 and 2010 BNE Peaker Calculations. Note that as the BNE Peaker for 2009 was located in the Republic of Ireland and the 2010 Peaker located in Northern Ireland, some of the variances in the table below are due to some cost structures being different depending on the jurisdiction.

| Comparison of Costs for 2009 and 2010 BNE Peaker Calculatations (All figures in €000's) | 2009 Decision | 2009 Decision with Uplift | 2010 Consultation | Variance | % Variance | Comment |
|---|---|---|---|---|---|---|
| **Site Procurement** | **3,221** | **3,801** | **1,425** | **-2,376** | **-63%** | Due to the significant movements in the economy over the last year, the value of land has reduced. An independent assessment was carried out on current land values, and the RAs are satisfied that the estimate for 2010 is an reasonable reflection of the current costs. |
| **Pre Financial Close Costs** | | | | | | |
| Owner's manpower costs up to contract award | 893 | 1,054 | | | | There is no direct comparison of this cost in 2010 . These costs have been captured in the category 'Other Non EPC costs' (see below). |
| Financial, legal costs, engineering, consultancy and EIA | 1,191 | 1,405 | | | | There is no direct comparison of this cost in 2010 . These costs have been captured in the category 'Other Non EPC costs' (see below). |
| **Total Pre-Financial Close Costs** | **2,084** | **2,459** | **0** | | | |
| **Post Financial Close Costs** | | | | | | |
| **EPC Contract (including contingency)** | 59,531 | 70,247 | 89,397 | 19,150 | 27% | EPC costs are higher than 2009 due to using latest version of GT Pro, which includes increase costs submitted from suppliers. In addition CEPA/PB included a 3.8% uplift to reflect their experience in the market.<br>Note also that the Distillate Facilities and Water Injection costs are included in the 2010 EPC Contract costs. |
| **Distillate Facilities** | 906 | 1,069 | | | | This cost is included in the 2010 EPC Contract costs. |
| **Water Injection (NOx reduction)** | 2,200 | 2,596 | | | | This cost is included in the 2010 EPC Contract costs. |
| **EPC Total** | **62,637** | **73,912** | **89,397** | **15,485** | **21%** | **Overall, the estimate for 2010 for EPC is 21% higher than the figures used for 2009.** |

| Comparison of Costs for 2009 and 2010 BNE Peaker Calculatations (All figures in €000's) | 2009 Decision | 2009 Decision with Uplift | 2010 Consultation | Variance | % Variance | Comment |
|---|---|---|---|---|---|---|
| **Electrical Interconnection** | 5,300 | 6,254 | 7,400 | 1,146 | 18% | The figures for 2010 show an increase and are as a result of discussions with the TSOs and are therefore deemed as accurate.. |
| **Other costs** | | | | | | |
| Owners manpower during construction | 1,191 | 1,405 | | | | There is no direct comparison of this cost in 2010 . These costs have been captured in the category 'Other Non EPC costs' (see below). |
| Taxes, insurance during construction | 298 | 352 | 805 | 453 | 129% | This cost is higher that the 2009 estimate, mainly due to the fact that it has been calculated as % of the EPC costs and the EPC costs for 2010 are higher than 2009. Note that a higher % estimate has been used in 2010 (0.9% vs 0.5%). |
| Purchased electricity, fuel during construction | 298 | 352 | | | | There is no direct comparison of this cost in 2010 . These costs have been captured in the category 'Other Non EPC costs' (see below). |
| T&SC Fees | 6 | 7 | 5 | -2 | -29% | This cost is largely in line with the costs estimated in 2009 and map to the published tariffs. |
| Contingencies | 1019 | 1,202 | 4,649 | 3,447 | 287% | There is an increase in the level of contingency recommended for 2010 from CEPA/PB. |
| Interest during construction | 2,934 | 3,462 | 3,609 | 147 | 4% | This cost is largely in line with the costs estimated in 2009. The 2010 figure includes the estimates for Financing and IDC. |
| Other Non EPC costs | | 4,216 | 8,046 | 3,830 | 91% | A different approach was used in the calculation of this cost for 2010, where PB applied a % of EPC on these costs based on their industy experience. As a result of the higher EPC cost for 2010, this cost is also higher than 2009 |

| Comparison of Costs for 2009 and 2010 BNE Peaker Calculatations (All figures in €000's) | 2009 Decision | 2009 Decision with Uplift | 2010 Consultation | Variance | % Variance | Comment |
|---|---|---|---|---|---|---|
| **Total Other costs** | **5,746** | **10,996** | **17,114** | **6,118** | **56%** | |
| **TOTAL INVESTMENT COST** | **78,988** | **93,206** | **115,336** | **22,130** | **24%** | The overall investment cost for 2010 is higher than the costs for 2009, mainly due to the increase in the EPC estimate |
| Land & Fuel Residual Value | | | **-1,033** | | | An adjustment had been made in 2010 to account for the residual value of the Land and Fuel. |
| Initial Working Capital | | | **5,364** | | | An estimate was made of the initial working capital required . This includes the initial fuel required. |
| **TOTAL ADJUSTED INVESTMENT COST** | **93,206** | **93,206** | **119,667** | **26,461** | **28%** | Overall the Capital costs for the BNE peaker has increased by 29%. This is mainly due to the increase in EPC costs increasing and the fact that some of the other costs are calculated as a % of the EPC Costs. |
| **Capital Cost** | | | | | | |
| Capex | | 93,206 | 119,667 | 26,461 | 28% | |
| Plant life (Years) | | 15 | 20 | 5 | 33% | The change to the plant life is as a result of detailed discussions with CEPA and PB. The RAs have accepted the expert advice in regards to this and agree that 20 years is an appropriate estimate for the economic life of a plant with an expected relatively low output. |
| WACC (%) | | 7.07% | 7.13% | | | A direct comparison of the WACC is not appropriate as they apply to different jurisdictions. |

| Comparison of Costs for 2009 and 2010 BNE Peaker Calculatations (All figures in €000's) | 2009 Decision | 2009 Decision with Uplift | 2010 Consultation | Variance | % Variance | Comment |
|---|---|---|---|---|---|---|
| **Fixed Costs** | | | | | | |
| Operations and Maintenance | | 1,176 | 1,782 | 606 | 52% | The increase in O&M costs is due to the fact that the preferred plant for 2010 is larger that that used in 2009. |
| Transmission and SEMO charges | | 935 | 801 | -134 | -14% | These costs are derived directly from the published tariffs for 2009/2010. A direct comparison is not appropriate as the tariffs apply to different jurisdictions. |
| Insurance and Miscellaneous cost | | 1,008 | 1,430 | 422 | 42% | This cost has been calculated as a % of the EPC costs for 2010 resulting in a higher figure. |
| Rates cost | | 1,315 | 576 | -739 | -56% | The same assumptions from 2009 were used in 2010 for calculating rates. A direct comparison is not appropriate as the Rates apply to different jurisdictions. |
| Fuel Storage | | 164 | 190 | 26 | 16% | This minor cost is in the same region as that used for 2009. |
| **Total Fixed Costs** | | **4,598** | **4,779** | **181** | **4%** | **The overall estimate for fixed costs for 2010 is slightly higher. Some of the costs differ significantly due to the jurisdictional variances.** |
| **Annualised Capital plus Fixed Costs (€/kW)** | **93.81** | **93.81** | **85.16** | | | |
| Energy Market Infra Marginal Rent | | -0.0007 | 0 | | | |
| Ancillary Service Revenue | | -6.69 | -5.05 | | | The AS Costs has reduced from 2009 as a result of the new AS Harmonistation rules that are currently under consultation. |
| **Final BNE Cost** | | **87.11** | **80.11** | **-7** | **-8%** | **The Final BNE Cost for 2010 is lower, mainly due to the application of a 20 year plant life.** |

**Table A2.1** – Comparison of Costs for the 2009 and 2010 BNE Peak

# 18 APPENDIX 3 – CEPA REPORT TO RAS ON FIXED COSTS OF A BNE PEAKING PLANT FOR 2010