Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

Utility Regulator

ELECTRICITY GAS WATER

Single Electricity Market

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

Decision Paper

27th August 2009

SEM-09-087

1 CONTENTS

2 SUMMARY OF DECISIONS

The Best New Entrant (BNE) Peaking Plant for 2010 is an **Alstom GT13E2** firing on **distillate fuel**, sited in **Northern Ireland**.

The estimated annualised fixed cost, net of estimated infra-marginal energy rent and ancillary service revenue, is **€80.74/kW/year.**

The Capacity Requirement for 2010 is **6,826MW.**

The product of these price and quantity elements yields an Annual Capacity Payment Sum (ACPS) for the 2010 Trading Year of **€ 551,133,375**

When comparing the above figures to those proposed in the Consultation Paper ('Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2010' (SEM-09-072)) , the following items have been reviewed and changed in calculating the final annualised fixed cost of the BNE Peaker:

1) The Fuel Storage requirement has been increased from 3 Days to 3.5 Days to allow for the security of supply and operational requirement.

2) The Ancillary Services Costs have been update to reflect the inclusion of an appropriate estimate of the penalties likely to be faced by the BNE Peaker.

3) The Capacity Requirement has been updated to reflect an update to the Northern Ireland Demands Forecasts and an increase in the amount of wind generation available in 2010.

The table below shows the changes between the Consultation Paper and the Decision Paper.

Investment Costs	Consultation Paper	Decision Paper	Variance
EPC Costs	89,397,000	89,569,000	172,000
Site Procurement	1,425,000	1,425,000	0
Electrical connection Costs	7,400,000	7,400,000	0
Gas connection	0	0	0
Water connection	0	0	0
Owners Contingency	4,649,000	4,649,000	0
Financing Costs	1,788,000	1,788,000	0
Interest During Construction	1,821,000	1,821,000	0
Construction Insurance	805,000	805,000	0
Initial Fuel working capital	2,665,000	3,110,000	445,000
Other non EPC Costs	8,046,000	8,046,000	0
Accession & Participation Fees	5,000	5,000	0
Total	**118,000,000**	**118,618,000**	**618,000**

Recurring Costs	Consultation Paper	Decision Paper	Variance
Transmission & Market operator charges	801,000	801,000	0
Gas Transmission Charges	0	0	0
Operation and maintenance costs	1,782,000	1,782,000	0
Insurance	1,430,000	1,430,000	0
Business Rates	576,000	576,000	0
Fuel working capital	190,000	222,000	32,000
Total	**4,779,000**	**4,811,000**	**32,000**
Summary of Costs & Annualised Calculation	**Consultation Paper**	**Decision Paper**	**Variance**
Investment Cost (excl Fuel Working Capital	115,335	115,507	172
Initial Working Capital (including Fuel)	5,366	5,810	444
Residual Value for Land & Fuel	-1,033	-1,145	-112
Total Capital Costs	**119,668**	**120,172**	**504**
WACC	7.13%	7.13%	0.00%
Plant Life (years)	20	20	0
Annualised Capex	11,410	11,458	48
Recurring Cost	4,779	4,811	32
Total Annual Cost	**16,189**	**16,269**	**80**
Capacity (MW)	190.1	190.1	0
Annualised Cost per kW	**85.16**	**85.58**	**0.42**
Final BNE Cost	**Consultation Paper**	**Decision Paper**	**Variance**
Annualised Cost per kW	85.16	85.58	0.42
Ancillary Services	5.05	4.84	-0.21
Inframarginal Rent	0.00	0.00	0.00
BNE Cost per kW	**80.11**	**80.74**	**0.63**

Table 2.2 – *Comparison of Costs for Alstom GT13E2 in Consultation and Decision Papers.*

3 INTRODUCTION

On 1 July 2009, the Regulatory Authorities (RAs) published a consultation paper on the 'Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2010' (SEM-09-072). The approach used in the calculation of the BNE Peaker Costs and the Capacity Requirement was the same as has been employed in previous years.

The RAs 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. CEPA and PB also assisted the RAs in the review of the responses to the consultation paper.

The RAs received 15 responses to the consultation (SEM-09-072). These are published along with this paper. Responses were received from the following parties:

- Airtricity
- Bord Gais Energy
- Bord Gais Networks
- Bord na Mona
- The Consumer Council for Northern Ireland
- Endesa Ireland
- ESB International
- ESB Power Generation
- IWEA
- Joint Development Agency (Forfás, IDA Ireland and Enterprise Ireland)
- NIE Energy Limited - Power Procurement Business (PPB)
- NIE Energy Supply
- Premier Power Limited
- Virtutility Limited
- Viridian Power & Energy Limited

The responses provided were fully assessed and considered by the RAs in the determination of the decisions laid out in this paper. In addition, a number of respondents requested meetings with the RAs to discuss their responses. These meetings were held with the RAs and CEPA/PB in August 2009. This document includes the full calculation of the final BNE Fixed Cost, the final Capacity Requirement and the final Annual Capacity Payment Sum (ACPS) for the calendar year 2010. Detailed responses are provided by the RAs to the individual comments provided by respondents in Appendix 1.

The work carried out by the RAs and their consultants has been presented to the SEM Committee enabling the SEM Committee to make the final decisions on the settings and costs to be used for the Annual Capacity Payment Sum (ACPS) for the calendar year 2010.

4 TECHNOLOGY OPTIONS

4.1 TECHNOLOGY OPTIONS FROM CONSULTATION PAPER

In the consultation paper (SEM-09-072) the RAs detailed the approach used in determining the technology to be used for the BNE Peaker. A long list of options was initially assessed using the selection criteria defined. This process resulted in a shortlist of 4 options. From these a screening curve analysis was completed resulting on a final proposal. The proposed technology option for the BNE Peaker 2010 is the Alstom GT13E2.

4.2 RESPONSES TO TECHNOLOGY OPTIONS

Ten respondents provided comments in relation to the technology option proposed in the consultation paper. A number of respondents welcomed the added transparency and comprehensive approach to the selection process and the inclusion of costs for both the gas and distillate fuel options. The main areas where concerns were raised were:

- Technology Choice
- Unit Output
- Provision for Outages
- Fuel Choice
- Environmental Requirements

The specific comments relating to these areas are discussed below. Other points raised in relation to the choice of technology were:

- One respondent highlighted that efficiency is related to total costs over the lifetime of an investment. In order to accurately reflect the true costs, the total expected costs should be discounted over the total lifetime of the investment, which will appropriately reflect the relationship and choice between cost and efficiency.

- One respondent objected to the exclusion of AGUs arguing that an AGU comprises numerous small-capacities, distribution-embedded diesel generators operating in export mode. This means that AGUs generate at their full individual capacity irrespective of the site load and therefore the aggregated capacity can be totally guaranteed.

4.2.1 TECHNOLOGY CHOICE

Most respondents either agreed with or did not specifically comment on the proposed choice of Technology for the 2010 BNE Peaker.

One respondent highlighted that the short-listed options for the preferred BNE were all units with an output greater than 160MW. They proposed that the RAs should be considering smaller units and promoting the location of these plants in the same areas as wind farms. Another respondent suggested that the system requires extremely flexible aero-derivative plant to meet peaking requirements and that this flexibility will become increasingly important with the future proliferation of renewable energy plants. It was also suggested that the RAs' technology selection is at odds with the technology proposed by EirGrid in the 2007 "fast build" consultation process which they conducted on behalf of CER. The fast build consultation suggested that the All Island Market (AIM) required multi-site aero-derivative engine installations for peaking purposes (ideally 3 x 60MW sites).

A respondent suggested that it was not clear why the size or particularly ramp rate of the plants is used in the selection criteria. Another queried the definition of a 'proven technology' as a technology where there are 3 examples of over 8,000 running hours.

A final point raised by a respondent proposed that the RAs review whether a 20 minute start-up time is still acceptable, given the increasing penetration of wind in the island and suggested improved security of supply with the use of aero-derivative power plants with 10 minute start-up time.

4.2.2 UNIT OUTPUT

A number of respondents compared the unit output for the Alstom GT13E2 of 190MW in the 2010 paper to the 2007 paper where it was quoted as an 182MW plant and queried why there was a difference. One respondent requested further clarity regarding the capacity of the proposed unit as the 2009 BNE paper showed the capacity of the Alstom GT13E2 as 180.2MW.

A respondent quoted the average lifetime output figures from GTW 2009 and queried whether Alstom would guarantee the output figure of 195MW figure used to derive the average lifetime net output of 190.1MW specified. They also suggested that water injection systems for liquid fuel firing are common but on gas firing it is not normal practice. One respondent queried the output degradation of the BNE plant suggesting that the life time extension would increase the degradation experienced by the machine.

4.2.3 PROVISION FOR OUTAGES

A number of respondents asked for clarity in relation to how the output power and efficiency degradation values were calculated. Another queried whether provisions for forced and scheduled outages were included in the calculations. They suggested that the values for these parameters used in previous years are reasonable.

4.2.4 FUEL CHOICE

One participant highlighted that a gas plant has inherent auxiliary security of supply benefits as they are dual fuelled. In addition, they suggested that fuel prices over the lifetime of the plant should be considered in BNE calculations as in this scenario a gas fired plant would generate electricity at a lower cost than distillate.

4.2.5 ENVIRONMENTAL REQUIREMENTS

One respondent noted that as Government policies and initiatives to reduce carbon emissions, carbon prices are likely to increase significantly over the life of the plant. A 'reasonable investor' would factor this increase into their choice of plant and suggested that it is reasonable to question whether a rational investor would consider building a distillate plant at this stage.

One respondent suggested that the selection of a distillate-fired BNE would result in additional costs being incurred in the planning permission and IPC licence application processes that should be taken into account in the BNE fixed-costs.

Another comment related to the level of emissions used, proposing the use of the lower Emissions Limit Value (ELV) value of 90Mg/Nm3 for distillate as set out in the Industrial Emissions Directive (IED).

4.3 DECISION ON TECHNOLOGY OPTION

Regarding the Technology choice, in the process of developing the consultation document the RAs and CEPA/PB met with the Transmission System Operators (TSOs) (SONI in Northern Ireland & EirGrid in Republic of Ireland) to discuss and agree the appropriate assessment criteria. To the extent practicable the RAs sought to ensure consistency with criteria used in previous years and to use criteria which reflected the needs of the system.

In the analysis carried out, a number of plant type, including aero derivative units were considered. In addition, in the discussions with the TSOs on the type of plant that would be of benefit to the network did not result in a particular unit type or size being given preference. Based on these facts the recommendation came down to what decision would a rational investor make. The use of a screening curve to show the costs profile resulted in the large machines being short listed.

In relation to the 'proven technology' query, CEPA/PB considered that the assumption of 3 examples of units with over 8000 running hours is applicable to industrial GTs as in their experience it accords with the period which lead insurers typically use for such type of machine. The RAs took note of the comments raised at the stakeholder seminar in May 2009, where a number of attendees questioned the 8,000 running hours criteria. As a result, CEPA/PB revisited the long-list of plant and, where there was evidence to suggest that parties were investing in a particular option these plants were included within the list for consideration.

In relation to the 20 minute start-up time, this criterion was based on discussions with the TSOs. At this stage, the RAs do not see any merit in using a shorter time frame than that proposed by the TSOs. The RAs will liaise with the TSOs on this area and any changes in this criterion as a result of increased renewable generation may feed into future BNE calculations.

Regarding the Unit Output, two factors have resulted in an output higher than the rated ISO power output:

- Firstly, as detailed in Annex 2 of the CEPA/PB report, water injection used for NOx control and power augmentation has been considered in the evaluation.

- Secondly, the RAs, following discussions with the TSOs, decided to base the power output on the ambient conditions at the grid's most critical time and the time when, other things being equal, the BNE plant would be most likely to operate, i.e. winter peak load. These demand loads occur when temperatures are low, resulting in an increase in GT output.

In relation to the provision for outages, the RAs wish to clarify that the same assumptions for planned outage duration (13 days) and forced outage rate (2%) as had been used in previous years were included within the modelling for the calculation of the costs of a BNE plant in 2010. The RAs acknowledge that these assumptions should have been included in the consultation paper.

For the query regarding fuel choice, the current methodology for the calculation of the BNE Peaker means that the fuel costs over the lifetime of the plant are not considered. In addition, the fuel costs relating to the infra marginal rent for the selected peaker for the year in question are only determined at the end of the calculation process. The RAs would also highlight that forward fuel price predictions can be subjective and could increase the volatility and risk associated with the BNE calculations.

Under the Environmental Requirements, whilst the RAs recognise that the proposed IED may change the recommendations for Best Available Techniques (BAT) and may propose tighter emissions requirements with which the BNE plant would need to comply (either initially or via retrofitting abatement equipment) the RAs note that the final form of the IED has yet to be finalised. The RAs also note that the currently proposed 90mg/Nm3 requirement for distillate firing is achievable by the selected Alstom GT13E2. As such, the RAs do not consider that there is compelling evidence to suggest that additional investment would be undertaken to meet these requirements.

Regarding the point raised regarding carbon emissions. The RAs note that there are considerable uncertainties and difficulties associated with predicting the future price of carbon, due to uncertainties about future phases of the Emissions Trading Scheme and other environmental policies. These factors, combined with the low running hours, mean that the RAs do not consider it necessary to address the issue here. As the Plexos model revealed that the peaking plant would not be required to run, the RAs do not consider that carbon emissions would be significant.

Regarding the query relating to efficiency versus cost, because of the nature of the BNE plant and given the evidence of very low running hours provided by Plexos modelling, the RAs do not consider that there is compelling evidence to suggest that the plant's operating pattern would change markedly over its lifetime. As such, the RAs do not consider that a rational investor would incur significant upfront costs in order to install a more efficient machine and consider that this assumption remains applicable.

Finally, the RAs acknowledge the clarification regarding the AGUs and as highlighted in the consultation paper the RAs intend to investigate this area in more detail as part of the CPM Medium Term Review.

Overall, the purpose of this exercise is to determine the costs that would be incurred by a rational investor in a new entrant peaking plant. The methodology used by the RAs and their consultants considered a full range of potential candidate plant and reduced that list using a series of criteria which were discussed and agreed with the TSOs; eventually leading to the identification of the most appropriate option. While the RAs recognise that in some cases the respondents views may differ, the RAs have not been presented with evidence to suggest that the plant choice was inappropriate.

In summary, the SEM Committee are content that a rigorous assessment has been made of the technologies available and the proposals as detailed in the consultation should be used for the BNE Peaker for 2010. Therefore the SEM Committee have decided that the BNE Peaker for 2010 is the Alstom GT13E2. The Unit output of this plant is 190.1MW

The Technology Option for the BNE Peaker 2010 is the <u>Alstom GT13E2</u>

5 INVESTMENT COSTS

5.1 INVESTMENT COSTS FROM CONSULTATION PAPER

In the consultation paper, the RAs discussed the key cost areas that make up the capital costs of the BNE Peaker. The key cost areas given consideration were:

- Engineering, Procurement & Construction (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

5.2 RESPONSES TO INVESTMENT COSTS

Nine respondents provided comments in relation to the capital costs proposed in the consultation paper. A number of respondents were broadly in agreement with the assumptions and calculations presented in the consultation paper. However other respondents felt that the costs were understated and would be insufficient to ensure the entry into the SEM of an actual best new entrant plant. One respondent felt that overall the BNE cost was 16% lower than its internal analysis.

The main areas where concerns were raised were:

- EPC Costs
- Site Procurement costs
- Electrical Connection costs
- Gas and Make-up Water Connection costs
- Financing, Interest During Construction (IDC) and Construction Insurance
- Up front costs for fuel working capital

The specific comments relating to these areas are discussed below.

5.2.1 EPC COSTS

One respondent acknowledged that the approach used for the EPC calculations gives a more realistic estimate of the capital costs of peaking plant and recommended that this more robust methodology be continued in future years. Another respondent noted that the costs that the RAs included in the consultation paper are within the same ballpark as the costs that they had received from vendors. However another respondent felt the EPC estimates were too low. A further view was stated where a respondent felt that they would have expected the BNE cost to have fallen by more than the proposed reduction of eight percent given the continued, significant decline in capital costs internationally and recommend that the regulators revisit the cost assumptions, particularly for capital costs, to ensure that they fully reflect the current cost of capital investment.

Another respondent raised a specific concern over the use of a separate EPC Contractor from the GT manufacture. While acknowledging that this option may be less expensive, they suggest that the risk of the project will increase and this should be reflected in the calculations.

A further comment was in relation to the 3.8% multiplier applied to the EPC costs based on UK experience. It was proposed that the costs in Northern Ireland and Republic of Ireland would be higher considering items such as transport costs, labour costs, accommodation costs etc. Furthermore, it was also questioned whether the EPC costs would be the same regardless of location (Northern Ireland vs. RoI). Another respondent stated that they considered the 3.8% multiplier to be an arbitrary adjustment factor.

One responded raised a concern in relation to the exchange rate used. They highlighted that the assumed rate of 1.12 euros to the pound (which dates back to at least 15 June 2009) cannot be replicated or hedged by a potential BNE investor. They added that the consultants' report notes that the exchange rate of 1.12 euros to the pound was the spot rate at the time of developing the document and is viewed as the best indicator of future rates. Based on the respondents past experience, they stated that this assumption is unrealistic (especially over the last twelve months) and cannot be justified. They proposed that currency and other key factors should be updated in the decision paper, similar to the approach proposed by the RAs to the Demand Forecasts.

5.2.2 SITE PROCUREMENT COSTS

It was acknowledged by one participant that the 20,600m^2 site area as suggested is fitted to the footprint of the Alstom GT13E2.

One respondent highlighted that finding a site close to an existing 220KV sub-station which is appropriately zoned is extremely unlikely and the land costs associated with such a site would be excessive. In addition, they stated that the deemed the estimated reduction of 63% in the price per m^2 compared with last year price is too aggressive and in their experience a price drop more like 35% to 40% would be appropriate.

One respondent suggested that a site with planning for power generation would be worth considerably more than normal and asked if this had been accounted for in the calculations.

One respondent raised a concern about the impact that the 63% decrease in site procurement costs in one year has on investors. They suggest that the volatility sends negative signals to the global energy and financial markets and will impinge on future investments in the SEM. They proposed that the process for calculation needs to be stabilised and levelised over a number of years.

5.2.3 ELECTRICAL CONNECTION COSTS

One respondent questioned the viability of connecting a nominal 190MW plant to the 110KV system in Northern Ireland and suggested a 220kV connection would be more realistic and the costs should be adjusted accordingly. In addition, they highlighted that EirGrid establish in its Node Assignment Rules that power plants with a capacity above 177MW shall be connected at either 220kV or 400kV.

5.2.4 GAS AND MAKE-UP WATER CONNECTION COSTS

One respondent suggested that the site in both jurisdictions should be nominal and therefore a water connection charge should apply in both Northern Ireland and the Republic of Ireland. A number of others suggested that there should be some water connection charge allocated to Northern Ireland as there would be an increased capacity in the water system that would be required for the power plant.

One respondent highlight that the gas connection charges of €3.38m for The Republic of Ireland is too high. Based on a load factor of 5% the plant would be subject to pay 30% of its connection costs rather than the full connection cost. They requested that this should be reflected in the calculations.

5.2.5 FINANCING, INTEREST DURING CONSTRUCTION (IDC) AND CONSTRUCTION INSURANCE

One respondent felt that the costs for Financial, Interest during Construction (IDC) and Construction Insurance were understated. They proposed that a 7% interest rate during construction over total cost should be used. Assuming a construction period of 18 months the IDC should be increased by a factor of at least five. They also proposed that the insurance cost should be also increased.

5.2.6 INITIAL FUEL WORKING CAPITAL

Two respondents raised a concern in relation to fuel storage and the assumption is to build storage and hold initial fuel stocks to enable 3 full days operation at full load. They proposed that the level of fuel stocking that must be held for the unit must be greater that the 3 day strategic requirement and suggested that an increase 33% for the distillate only options (to cover an extra day worth of fuel stocks to facilitate commercial operations on the distillate only configuration) was appropriate. This would increase the EPC costs for larger storage and fuel handling facilities and also result in higher Initial Fuel Working Capital costs. The second respondent raised the same concern but suggested an increase of 16.7% (equivalent to a half day of fuel).

5.2.7 OTHER INVESTMENT COSTS

The consultation paper also detailed costs in relation to the following areas:

- Owner's Contingency
- Other non-EPC costs
- Market Accession and Participation Fees

There were no specific comments received on the proposed costs in the consultation paper.

5.3 DECISION ON INVESTMENT COSTS

In relation to the EPC Costs, the RAs are content that a rigorous assessment of these costs was carried out by the CEPA/PB and the proposed costs in the consultation paper are valid. A number of respondents indicated that the costs presented were in a similar range to the costs estimates they have experienced and this further justifies the proposed costs.

In relation to the multiplier used on the EPC Costs (3.8%), the adjustment factors were derived from a database reflecting information from a series of recent projects which CEPA/PB considered provide relevant comparators to a BNE plant. A multiplier was used as the cost data is confidential and cannot be put in the public domain. The RAs robustly challenged CEPA/PB about the derivation of the multipliers and are content that the proposed multiplier is fair and appropriate.

The RAs note the point about higher costs for constructing a plant on the Island of Ireland but (based on our discussions with CEPA/PB) do not consider that there is evidence to suggest that costs would be an order of magnitude higher than in the countries reflected in the data that is used to compile the EPC cost multipliers. This also applies to the argument that the EPC costs would be different on a jurisdictional basis.

The RAs disagree with the proposal to update the exchange rate in this decision paper. It was decided that the spot rate was appropriate, especially during a time of currency fluctuations.

In relation to the Site procurement costs, the RAs recognise that property prices have been particularly volatile over recent years. The RAs also recognise that some sites, such as those with access to an electricity, gas and water connection may, in some cases, attract a price premium. Land costs were an area which the RAs were keen to explore in detail and, as such, CEPA/PB commissioned an independent property market expert with direct experience of power project investment to advise on cost estimates. The RAs are satisfied that the quotations provided reflect the market value and have decided that the costs detailed in the consultation paper reflect the market value.

Regarding the Electrical Connection Costs, for the Republic of Ireland option, the costs quoted in the consultation were based on a 220kV connection. For the Northern Ireland option, the costs were based on data provided by the TSOs. During the discussions, the TSOs confirmed that an 110kV link was suitable for the proposed site in Northern Ireland.

Regarding the water charges, the RAs have decided that no additional provision needs to be made for the water connection charges. CEPA/PB provided details that the connection cost for 25mm diameter water pipe is £216 and that it is unlikely that the connection cost for a 4 inch pipe will be material to the calculation. In addition the cost for piping within the battery limit of the plant has been included within the original calculation. The demineralisation plant has been sized for 50% of the maximum full load plant requirement, thus no more than 25t/h will ever be drawn from the existing header at Belfast West and no infrastructure changes are foreseen.

The RAs note the comment in relation to the peaker plants paying only a 30% contribution for their connection up front. This facility was primarily intended for use by industrial and commercial customers but could potentially be used by peaking plants with low load factors. The BGN connection policy is under review in CER at the moment and while this issue remains under consideration by the CER, this paper assumes a 100% connection contribution.

Interest during Construction (IDC) is used to represent the interest charged on the loan amounts drawn down during the construction period. As these loan amounts are drawn pre-commercial operations and hence pre-revenue flows, IDC is often capitalised and added to the total project cost. This is the approach that CEPA/PB has taken in modelling. In order to model IDC, CEPA/PB made assumptions about when loan amounts are drawn (in line with assumptions about phasing of construction and gearing), and capitalised those amounts using the mid-point WACC. CEPA/PB also cross-checked this approach to a simple interest-only calculation on loans drawn (assuming debt and equity are drawn in proportion to the assumed 60% gearing, and that interest is only paid on balances actually drawn). This cross-check has produced similar results to the initial modelling.

In addition, CEPA/PB cross-checked the IDC assumptions with a project financier, enquiring whether there is likely to be any premium on the components of the WACC charged during the construction period. The project financier confirmed that the assumptions are appropriate, and that minimal debt premium would be required during construction. As such CEPA/PB considers that the broad range for the cost of debt includes appropriate assumptions for interest rates applicable during the construction period.

The RAs agree with this approach and have decided that no additional costs should be added to this area. In relation to the Fuel Storage costs, the RAs acknowledge the point raised by 2 participants that the fuel storage allocation should be higher than the 3 day strategic requirement. The RAs have therefore decided to make an allocation of 3.5 days storage. This is based on the expected low run periods of the plant. Therefore the Working Capital for Fuel will increase to €3.11m. This change will also impact the Residual Value for Land and Fuel (see Table 9.1). In addition, the EPC Cost will increase by €172K to account for the additional storage facilities required.

In the absence of any comments on the other Investment areas (Owner's Contingency, Other non-EPC costs, Market Accession and Participation Fees), the RAs have assumed that respondents are generally content with the proposed costs and have decided that these costs shall be kept the same as detailed in the consultation paper.

As a result of the points above, the SEM Committee have decided that the investment costs relating to the Alstom GT13E2 are as detailed in the table below. The table summarises all the investment cost for each jurisdiction and for each fuel type.

Cost Item	Republic of Ireland Dual Fuelled	Republic of Ireland Distillate	Northern Ireland Dual Fuelled	Northern Ireland Distillate
EPC Costs	89,593,000	89,569,000	89,593,000	89,569,000
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	0	1,690,000	0
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	3,110,000	3,110,000	3,110,000	3,110,000
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	**120,763,000**	**117,302,000**	**120,363,000**	**118,618,000**

Table 5.1 – *Summary of Investment Costs for Alstom* GT13E2

As was the case in the consultation paper, it should be noted that the investment costs for the Distillate plant are less than the costs for the Gas Plant. The table below compares the costs detailed in the consultation with what has been decided by the SEM Committee.

Investment Costs	Consultation Paper	Decision Paper	Variance
EPC Costs	89,397,000	89,569,000	172,000
Site Procurement	1,425,000	1,425,000	0
Electrical connection Costs	7,400,000	7,400,000	0
Gas connection	0	0	0
Water connection	0	0	0
Owners Contingency	4,649,000	4,649,000	0
Financing Costs	1,788,000	1,788,000	0
Interest During Construction	1,821,000	1,821,000	0
Construction Insurance	805,000	805,000	0
Initial Fuel working capital	2,665,000	3,110,000	445,000
Other non EPC Costs	8,046,000	8,046,000	0
Accession & Participation Fees	5,000	5,000	0
Total	**118,000,000**	**118,618,000**	**618,000**

Table 5.2 – *Comparison of Investment Costs for Alstom GT13E2 in Consultation and Decision Papers.*

6 RECURRING COSTS ESTIMATE

6.1 RECURRING COSTS FROM CONSULTATION PAPER

In the consultation paper, the RAs discussed the key cost areas that make up 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

The RAs noticed a typographical error in Table 7.1 in the consultation paper, where the figures for Operation and Maintenance costs did not reflect the figures in the CEPA/PB report. This error did not impact any of the calculations in the consultation paper.

6.2 RESPONSES TO RECURRING COSTS

Five respondents provided comments in relation to the recurring costs detailed in the consultation paper. One respondent questioned why there was only a small increase in the costs when compared to the costs from 2009, considering operation and maintenance costs insurance costs have increased considerably. They suggested that these items should be reasonably stable in the shorter term, and that they should be adjusted year to year by an appropriate index or basket of indices. Another respondent also raised concerns regarding these costs and suggested that based on internal international benchmarking for open cycle gas turbines, the value for O&M costs should be between 10-15 €/kW-year and the insurance cost should be increased because under the financial crisis the insurance companies are raising their fees.

Another respondent questioned whether a Long-term service agreement (LTSA) costs was included and asked for the detail behind the non EPC costs detailed in the consultation paper.

Another area of concern was in relation to the Gas Transmission Charges. One respondent stated that it was not clear why the RAs used the 2008/09 capacity charge rates for Northern Ireland when estimated 2009/10 rates were also published and are slightly higher. The respondent also noted that revised charges for 2009/10 are due to be published soon and suggested that these figures should be used. One respondent proposed that although it could be argued that a peak plant with a very low load factor would only run a short period (4 hours), a more appropriate assumption would be the needed to run during 8 hours (the value of GSS Loss of Load Expectation per annum) so the Gas Transmission Charges should be €1.6M. Another respondent suggested that a 12-hour operational requirement would be appropriate.

One respondent flagged that in line with our previous point in relation to the fuel stocking requirements for the distillate only option, the recurring fuel working capital cost would also be higher. Also, they suggested that in their experience, the business rates for Northern Ireland were €15K too low.

6.3 DECISION ON RECURRING COSTS

In relation to the O&M costs, the RAs can confirm that the Long-term service agreement (LTSA) costs were included in the fixed annual maintenance component of the O&M costs. This is described in section 4.4.3 of the CEPA/PB report that was published along with the consultation paper.

In relation to the query on benchmarking O&M costs, the RAs note that it is difficult to respond to this statement without supporting evidence. The RAs would be particularly keen to understand the international benchmarking and justification for the suggested 10-15€/kW-year assumption in more detail. CEPA/PB's approach applied changes to cost estimates to reflect PB's past project experience, including of projects in Ireland, and their understanding of the market for power project development. Hence the assumptions presented in the CEPA/PB report are based on their own international benchmarking.

The insurance cost estimate provided by CEPA/PB was based on a proportion of the EPC price and was based on CEPA/PB's experience of previous projects. CEPA/PB have not seen evidence of a sustained rise in insurance costs.

The RAs would welcome evidence in support of this statement that the rates estimates for Northern Ireland were too low. The rates calculations were based on figures obtained from formulae available from the Land and Property Services website.

In respect of gas transmission charges, the RAs agree with respondents that it is appropriate to use the most recent figures for gas transmission charges. For the Republic of Ireland the figures are now based on the CER's Draft Decision on Gas Transmission Allowed Revenue[1] and Tariffs 2009/10 and for Northern Ireland the figures are based on forecast tariffs for 2009/10[2]. For Northern Ireland the figure is revised to £0.32938/kW.

The RAs note the different views that have been expressed regarding the appropriate basis for calculating gas transmission charges. On balance, the RAs consider that the 4 hour running assumption remains reasonable. The RAs note that there was an error in the calculation which led to the figures for gas transmission charges in the consultation document. These are rectified as follows:

- No conversion from higher to lower calorific value gas was made within the calculation. The calculation should therefore have divided the kWh figure by 0.903.
- The figures for gas transmission charges in Northern Ireland quoted the postalised tariff which includes allowance for both the onshore system and the SNIP (Scotland Northern Ireland Pipeline) interconnector. However, the Republic of Ireland figure used in the document only relates to the tariff for use of the onshore system. It therefore excludes the interconnector tariff

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[1] http://www.cer.ie/en/gas-transmission-network-current-consultations.aspx?article=02654350-67e4-44ea-a8ce-dfba12271a42

[2] http://www.bordgais.ie/files/networks/transportation/20080819035336_Postalisation%20Transmission%20Tar.pdf

and means the figures are not comparable. The RAs have therefore added the onshore tariff to the previous figure which only included the interconnector tariff.

As a result of these changes, the calculation of gas transmission charges in Republic of Ireland becomes.

Total Gas Transmission Charges = (Plant Output/ Load Factor/ Calorific Value Conversion Factor) x Running Hours x (Onshore Tariff + Interconnector Tariff)

Numerically this becomes: (193,600kwh/0.3491/0.903) x (4) x (0.432614 + 0.221618) = €1,607,000The Northern Ireland cost has also been modified to account for the updated tariff and the calorific value of 0.903. This results in the Northern Ireland Cost being €906,000

In summary, the RAs have decided that there will be minimal changes to the recurring costs. The only change is to the Fuel working capital cost to reflect the decision to increase the storage facilities from 3 days to 3.5 days. The costs are summarised in the table below.

Cost Item	Republic of Ireland Dual Fuelled	Republic of Ireland Distillate	N Ireland Dual Fuelled	N Ireland Distillate
Transmission & Market operator charges	1,099,000	1,079,000	816,000	801,000
Gas Transmission Charges	1,607,000	0	906,000	0
Operation and maintenance costs	1,807,000	1,782,000	1,807,000	1,782,000
Insurance	1,431,000	1,430,000	1,431,000	1,430,000
Business Rates	1,516,000	1,489,000	587,000	576,000
Fuel working capital	212,000	212,000	222,000	222,000
Total	**7,672,000**	**5,992,000**	**5,769,000**	**4,811,000**

Table 6.1 – *Summary of Recurring Costs for BNE Peaker for 2010*

Again it should be noted that as was the case in the consultation paper, the recurring costs for the Distillate plant are less than the costs for the Gas Plant and the changes to the Gas Transmission charges have increased the costs for the Gas Plant Options. The table below compares the costs detailed in the consultation with what has been decided by the SEM Committee.

Recurring Costs	Consultation Paper	Decision Paper	Variance
Transmission & Market operator charges	801,000	801,000	0
Gas Transmission Charges	0	0	0
Operation and maintenance costs	1,782,000	1,782,000	0
Insurance	1,430,000	1,430,000	0
Business Rates	576,000	576,000	0
Fuel working capital	190,000	222,000	32,000
Total	**4,779,000**	**4,811,000**	**32,000**

Table 6.2 – *Comparison of Recurring Costs for Alstom GT13E2 in Consultation and Decision Papers.*

7 OTHER POINTS RAISED IN CONSULTATION PAPER

7.1 COMMENTS RECEIVED BASED ON CONSULTATION PAPER

A number of respondents welcomed the transparent approach used by the RAs in the calculation of the Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2010, including the public workshop held at the start of the process.

However, some respondents felt that there was still a large element of regulatory risk in the process and this sends out a poor signal to future investors and banking institutions. In particularly, respondents were concerns about the 15% reduction when compared with the 2009 calculations.

In addition, a number of respondents provided comments that will be taken into consideration as part of the CPM Medium Term Review. One particular area of concern where further transparency and information was required was in relation to the Capacity Requirement calculations.

Other specific points of note are discussed below.

7.1.1 UNRECOVERABLE COSTS

One respondent raised a concern in relation to unrecoverable costs in the SEM. They flagged two areas where they believe costs cannot be recovered. They recently reviewed the costs associated with the dual-fuel requirements and found these to be approximately €25 million. These are fixed costs, which are currently unrecoverable in the SEM. Similarly connection to the gas transmission network is an unrecoverable fixed cost.

They noted that the RAs have been aware of this gap in the cost recovery mechanisms since market start, yet have not designed a mechanism for generators to recover these costs and have requested that a mechanism should be put in place as soon as possible to rectify this issue.

7.1.2 CHOICE OF JURISDICTION

One respondent questioned the approach of choosing the cheapest jurisdiction in an all island market. They felt it was inherently unfair to potential investors based in the Republic of Ireland or Northern Ireland for the BNE price to be based on an uncertain jurisdiction from one year to the next and proposed that a better approach would be to choose a mid point between the BNE price in Republic of Ireland and Northern Ireland.

7.2 DECISION ON OTHER POINTS RAISED

The concern raised regarding the issue of unrecoverable costs is outside the scope of this paper. Under the market mechanism, the capacity payments are designed to address some of the fixed costs with the remainder being addressed by the Infra marginal rent and the ancillary services. Gas capacity was decided as a fixed cost item under the second period of consultation on the BNE in 2007. The proposed choice of the BNE Peaker for 2010 as a distillate plant is based on it being the cheaper option. The viability of a new gas project relative to the proposed plant on distillate is not the focus of this paper.

Regarding the choice of jurisdiction, the RAs consider that in an all-island market an investor would be likely to appraise sites in both jurisdictions and take a view on the site which best met their needs, which would not support the use of some form of averaging of costs.

8 ECONOMIC & FINANCIAL PARAMETERS

8.1 ECONOMIC & FINANCIAL PARAMETERS FROM CONSULTATION PAPER

In the consultation paper and the CEPA report (Appendix 3 of SEM-09-072), extensive details were provided on the build up of the WACC parameters as well as the nature of the BNE investment.

The key conclusions for economic and financial parameters included in the consultation were:

- A reasonable estimate for the gearing of the BNE is 60%.
- The plant life for the BNE will be 20 years.
- The appropriate range for the BNE cost of debt is 4.50% - 6.25% in the Republic of Ireland and 4.00% - 5.50% in the UK.
- The appropriate range for the cost of equity for the BNE peaking plant is 6.90% - 8.75% in the Republic of Ireland and 6.90% - 8.50% in the UK.

In developing views on the relevant economic and financial parameters RAs and CEPA/PB consulted with providers of finance with direct experience of the Irish and UK markets and elsewhere. Those parties provided their views on appropriate financial parameters on a confidential basis.

8.2 RESPONSES TO ECONOMIC & FINANCIAL PARAMETERS

Eight respondents replied to this section and one respondent commissioned an independent assessment from NCB Corporate Finance. This report is published along with the responses to the consultation.

There were a number of areas where the majority of responses related to within the economic and financial parameters heading. These were

- Type of investor
- Economic Life of the Plant
- Financing Structure
- WACC Parameters

These are discussed under the subheadings below.

8.2.1 TYPE OF INVESTOR

A number of respondents debated whether the type of investor would be an integrated utility or an Independent Power Plant (IPP). The CEPA reported stated that the investor is more likely to be an integrated utility and that it was unlikely that debt would be raised at the project level. One respondent suggested that this approach could lead to discouraging IPPs to invest in the SEM.

8.2.2 PLANT LIFE

Eight respondents raised their concerns regarding the change to the plant life from 15 to 20 years. A number of respondents highlighted that this change would further increase the regulatory uncertainty and instability of this process and the uncertainty and risk for investors and potential investors.

One respondent stated that no concrete justification for this change has been offered by the RAs they also highlighted that given the significant advancement in renewable generation technologies and the projected reduction in the running order of all non-renewable generation, they consider that the utilisation of 15 year plant life remains appropriate, as all projections show that an OCGT will be unable to command the same merit order position in a competitive market environment in 15 years time.

A number of respondents suggested that such a change (the move from 15 to 20 years for the plant life) should be examined as part of the larger medium term review of the Capacity Payment Mechanism. Another felt that this change needed a comprehensive review.

One respondent noted that, when considering the appropriate plant life, it is important to recall that the SEM is a mandatory gross pool, with no long term Power Purchase Agreement (PPA) available for the BNE investor.

8.2.3 FINANCING STRUCTURE

Several respondents queried whether a 10 year average tenor was an appropriate assumption for debt finance and whether this was consistent with an assumed 20 year economic life. One respondent also noted that, if a ten 10 year tenor is assumed, then re-financing costs would need to be considered.

NCB Corporate Finance commented that given the current state of financial markets, it has been difficult for European utilities to raise Euro denominated debt of a 20 year term. They see 10 year funding costing 7.5% in nominal terms (5.6% real) based on recent market issuance.

8.2.4 WACC PARAMETERS

The specific comments raised on the WACC parameters are dealt with in Appendix 1 below. In general respondents considered the proposed WACC to be too low and in some cases provided arguments and references to back up their arguments. The ranges of WACC values proposed by respondents spread from

8.5% to 9.7%. The main areas of concern were in relation to gearing, cost of debt and cost of equity. These are discussed further below.

8.2.4.1 GEARING

Four respondents commented on gearing. One respondent considered that a BNE investor without the asset backing of regulated assets is likely to see gearing levels of 50% in future financings. Another respondent suggested that a 60% gearing was too high, while a third respondent considered it was inappropriate. The final respondent noted that, due to their view that the investor should be an IPP, the gearing assumption should be revised.

8.2.4.2 COST OF DEBT

One respondent (NCB Corporate Finance) proposed a real cost of debt of 5.60% and provided evidence of the cost of debt for recent market issuances (for example ESB's recent UK Private Placement). Another respondent noted that 'a German bond investment for 20 years is currently attracting 4.25% return'.

8.2.4.3 COST OF EQUITY

One respondent suggested that the after tax cost of equity assumed for both Republic of Ireland and UK markets is below the level that would be required to justify an investment decision in peaking plant under the current framework for cost recovery. They noted that the after tax cost of equity is a factor of risk free rate, tax rates, equity risk premium, asset beta and gearing. In general, they considered each of the parameter assumptions to be conservative, and when taken together to result in a cost of equity which is very conservative. They also argued that this result was particularly surprising given the continued economic financial uncertainty.

Several respondents quoted Ofwat's recent draft determination on the cost of capital for water and sewerage companies in the UK. Ofwat's paper[3] ("Future water and sewerage charges 2010-15: draft determinations") sets out, as a draft determination, an Equity Risk Premium (ERP) of 5.4%, which is the top-end of their consultant's range and drawn from the well-known work of Dimson, Marsh and Staunton and a risk-free rate of 2.0%.

8.2.4.4 OTHER COMMENTS RELATING TO WACC

One respondent stated that it is 'illogical' that there has not been an increase in the asset beta from last year's BNE decision.

Another respondent commented that an increase in the economic life of the BNE plant will increase the riskiness of the asset and should have a corresponding impact on the WACC.

[3] http://www.ofwat.gov.uk/pricereview/pr09phase3/prs_web_pr09dd

http://www.ofwat.gov.uk/pricereview/pr09phase3/det_pr09_draftchap5.pdf

8.3 DECISION ON ECONOMIC & FINANCIAL PARAMETERS

The RAs discuss the key points raised on the economic and financial parameters below.

8.3.1 TYPE OF INVESTOR

In relation to the type of the investor, the RAs are fully aware of the range of potential investors into the SEM, including integrated utilities, IPPs and indeed financial investors. The RAs have no intention of discouraging investment into the SEM and have taken account of the potential range of investors in setting the economic and financial parameters. CEPA/PB had a number of consultations with potential lenders and their experience is that a BNE-type investment may prove difficult to finance in the current market conditions on a stand-alone, purely non-recourse basis. In other words investors will expect to see some support at the group level, whether the group is an integrated utility or a diversified IPP investor. Therefore for the 2010 BNE Peaker, the RAs have decided that the type of investor is likely to be an integrated utility.

8.3.2 PLANT LIFE

The RAs recognise that the change in economic plant life assumption is a significant determinant of the final BNE annual price. In coming to this decision, the RAs along with CEPA/PB considered evidence from both Ireland and elsewhere, including considering the market structures in place. CEPA/PB recommended that it is relevant to look at investor decisions made in markets other than the SEM, as investors have a range of market opportunities to invest in, and their experience is that even in risky markets investors are willing to invest on the basis of a twenty year or more economic life.

In relation to PPAs, no long term PPA is available to an investor in the BNE plant, but nonetheless, it is relevant to consider examples of investor decisions from markets where long term PPAs are available, as some of those markets are more risky than the SEM (for example, due to higher levels of political and regulatory risk). CEPA/PB's observation is that even in those riskier markets, investors are willing to invest on a 20 year basis.

CEPA/PB also highlighted to the RAs evidence suggests that many peaking generation plants in the UK have already had a useful economic life of 20 years or more (as of mid 2005, there were 13 examples in the UK with over 25 years operational life), which might be expected to give some comfort to potential BNE investors.

In the 2009 BNE Decision Paper (SEM-08-109), the RAs stated that a residual value of the plant after the 15 year economic life was to be reconsidered for the 2010 BNE. In relation to this, CEPA/PB indicated that the residual value could be determined from the anticipated remaining actual life of plant, for which they have many examples of Open Cycle GT plant lives of 25 - 40 years. However, the RAs recognised that this approach would involve considerable uncertainty and an element of subjectivity. Therefore the assumption of an increased economic life and no financial residual value for the plant could therefore be argued to provide greater transparency for investors.

The RAs met with a number of participants to discuss their comments and concerns in relation to this matter. In this regard, the RAs also requested participants to provide evidence of their own investment appraisals. There was limited evidence provided in this regard. Following these discussions, the RAs are at this time, satisfied with the recommendations provided by CEPA/PB based on their experience and expertise with these projects and discussion with financial institutions.

8.3.3 FINANCING STRUCTURE

Regarding the financing structure, the RAs welcome the market evidence provided by NCB on ESB's recent private placement. However, the RAs note that debt premia quoted for the ESB placement are not significantly out of line with the range presented in the CEPA/PB report (3.0% - 4.0% for the Republic of Ireland and 2.5% - 3.5% for the UK) and applied in the estimate of the BNE cost of debt.

The RAs also note that in contrast with the market evidence presented in CEPA/PB's report, which is drawn from the public domain, the details of the ESB private placement are by definition private and therefore without knowing the details of this specific transaction the RAs cannot verify whether it is reflective of financing terms and pricing that a notional BNE plant investor would face in seeking to enter the SEM in 2010. The multi currency nature of the placement, as well as the fact that spreads having been quoted over swaps and benchmark bonds, also make the evidence hard to compare with the evidence provide in the CEPA/PB report.

In light of the ongoing uncertainties in financial markets, CEPA/PB has deliberately made a conservative assumption about the average debt tenor. This assumption of a 10 year average tenor has been cross checked with a project finance lender, and with evidence from bond issues, and the feedback from the market is that 10 years is an acceptable, but conservative assumption.

In the CEPA/PB modelling they assumed a 10 year repayment profile for debt finance and no refinancing and as such re-financing costs are not relevant. For the sake of clarity the assumption is that once the initial debt is repaid the project will be purely equity financed, which is again a conservative assumption.

8.3.4 WACC PARAMETERS

In relation to the WACC parameters and specifically gearing, the evidence presented in the CEPA report showed that gearing by likely investment-grade BNE investors is often sustained at rates over 60%. This evidence is supplemented by data provided by a lender. The RAs have therefore decided that the proposed level of gearing of 60% is appropriate.

Regarding the cost of debt, the evidence presented on a long-term German bond is not significantly out of line with the CEPA/PB research on Euro bonds (see Figure A6 of the CEPA/PB report), but as noted above, the RAs consider it more appropriate and more conservative to focus on 10 year debt.

The RAs note that respondents have chosen to quote Ofwat's draft determination (as discussed below) as evidence to support a higher cost of equity. However, they haven't referenced this report for the cost of debt figures. The Ofwat determination proposed a forward looking cost of debt of 4.1% to 4.3%', which is at the low end of CEPA/PB proposed range. Regarding the cost of equity, in line with the majority of regulatory agencies in Ireland and the UK, CEPA / PB have adopted a building-block approach as the primary tool for estimating the notional BNE peaking plant's WACC. This includes employing CAPM as the primary tool for estimating the BNE plant's cost of equity. The RAs believe this is the most robust methodology for the purposes of estimating the cost of capital for a notional BNE peaking plant.

As CEPA/PB note in their report "Estimation of the Equity Risk Premium (ERP) is fraught with difficulties". It is a variable whose value cannot be directly observed and hence is one of the more contentious parameters estimated when determining a company's WACC. Complicating matters further is that few studies concur on what the true value of the ERP is, or even the correct method for estimating it with many column inches in the literature given over to debating the relative merits of geometric means versus arithmetic means.

In the CEPA/PB analysis, they have considered the appropriate cost of equity for a BNE investor in 2010. They did not seek to critique values selected by the RAs and their adviser last year. CEPA/PB have advised that the asset beta selected is in the appropriate range, and is in line with evidence presented to Ofwat in recent weeks by their advisers. In addition, the RAs note that the estimate of the equity beta is greater than one and therefore that the investment is riskier than the market as a whole.

Overall the RAs find there is no compelling evidence received to merit a change the specific parameter assumptions used in the building block cost of capital estimate. Based on this the SEMC have decided that the WACC values detailed in the consultation paper will be used for the 2010 BNE calculations. These are summarised 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 8.1 – *Proposed WACC values to be used for the BNE Peaker for 2010*

9 BEST NEW ENTRANT PEAKER FOR 2010

9.1 SUMMARY OF COSTS

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. These figures reflect the changes as a result of increasing the fuel storage from 3.0 to 3.5 days.

Cost Item (000's)	Republic of Ireland Dual Fuelled	Republic of Ireland Distillate	Northern Ireland Dual Fuelled	Northern Ireland Distillate
Investment Cost (excl Fuel Working Capital	117,653	114,191	117,253	115,507
Initial Working Capital (including Fuel)	5,547	6,007	5,230	5,810
Residual Value for Land & Fuel	-1,243	-1,243	-1,145	-1,145
Total Capital Costs	**121,957**	**118,955**	**121,338**	**120,172**
WACC	6.80%	6.80%	7.13%	7.13%
Plant Life (years)	20	20	20	20
Annualised Capex	11,334	11,055	11,569	11,458
Recurring Cost	7,672	5,992	5,769	4,811
Total Annual Cost	**19,006**	**17,047**	**17,338**	**16,269**
Capacity (MW)	193.6	190.1	193.6	190.1
Annualised Cost per kW	**98.17**	**89.67**	**89.56**	**85.58**

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

One respondent requested that the RAs clearly indicate in their decision document what percentage of the fall in the BNE price (when compared to 2009) is due to expanding the plant lifespan from 15 to 20 years. In the case of the Northern Ireland Distillate option, the plant life of 15 years was used, the BNE Price would have been €95.3 per kW. Therefore the move to a 20 year economic life reduces the BNE Costs by €9.7 per kW. This equates to a reduction of 11.3%.

9.2 DECISION ON 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 Best New Entrant Peaker for 2010 is the Alstom GT13E2, located in Northern Ireland and uses Distillate fuel

10 INFRA MARGINAL RENT

10.1 INFRA MARGINAL RENT FROM CONSULTATION PAPER

As discussed in the consultation paper (SEM-09-072), in order 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 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 was assumed that there will be zero Infra Marginal Rent.

10.2 RESPONSES TO INFRA MARGINAL RENT

Four responses were received in relation to the proposed revenue from Infra Marginal Rent. Three of the respondents flagged that they were against the principle of deducting Infra Marginal Rent from the BNE price as it creates a perception of risk and unpredictable uncertainty and hence discourages efficient investment. One respondent agreed with the Infra Marginal Rent of zero based on their modelling.

One respondent queried the settings used for planned and force outages used for the BNE Peaker highlighting that in previous years it was assumed that planned outages of 13 days are typical and a forced outage rate of 2% was applied.

10.3 DECISION ON INFRA MARGINAL RENT

As detailed in the paper on the scope the medium term review of the CPM (SEM-09-035), the RAs intend to look at the Infra Marginal Rent Calculations. The comments raised in response to the BNE Calculations for 2010 will be given due consideration as part of the CPM Medium Term Review.

The RAs can confirm that the same assumptions for planned outage duration (13 days) and forced outage rate (2%) as had been used in previous years were included within the modelling for the calculation of infra marginal rent for a BNE plant in 2010.

Therefore for the purposes of the 2010 BNE Calculation, the SEMC have decided that there will be zero Infra Marginal Rent, as calculated for the consultation paper.

11 ANCILLARY SERVICES

11.1 ANCILLARY SERVICES FROM CONSULTATION PAPER

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)[4]. As highlighted in the consultation paper, 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 AS Calculations were:

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

11.2 RESPONSES TO ANCILLARY SERVICES

Seven responses were received in relation to the proposed revenue from Ancillary Services. The revenues were based on the harmonised rates published by the RAs in the recent consultation paper SEM-09-062. Two respondents felt that the AS estimates were too high, particularly when compared with the example for a peaker provided in the AS Consultation paper (SEM-09-062). A particular concern was raised at the inclusion of the 'Replacement reserve (DeSync)'. Additional information on the calculation and assumptions used in determining the AS revenues was also requested by a number of respondents.

A number of respondents raised concerns that the revenues proposed by the RAs did not fully consider the new set of charges and that there is no provision for AS penalties or other system charges (such as trips, short notice declarations, failure to provide reserve or generator performance incentive charges). The respondents requested that some level of contingency should be allowed for AS penalties and other system charges.

A number of respondents also raised the point that in their opinion the AS revenue should not be included in the BNE cost calculation as a new peaker is not guaranteed to receive an AS contract from the TSOs.

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

11.3 DECISION ON ANCILLARY SERVICES

In relation to the comments that AS revenue should not be included in the BNE cost calculation as a new peaker is not guaranteed to receive an AS contract from the TSOs, the RAs highlight that the AS payments to a BNE peaker is within the scope of the CPM Medium Term review and will be give due consideration.

In terms of the AS revenue, the RAs discussed the options with the TSOs in determining the appropriate revenue. It was agreed that a new BNE Peaker would be eligible for 'Replacement reserve (DeSync)' payments. Based on the latest revenue figures provided by the TSOs, the AS revenue is €960,383, as was detailed in the consultation paper.

The RAs acknowledge the comments received in relation to penalty payments and agree that a rational investor would make a provision for such costs. With this in mind, the RAs have applied penalties to cover the scenario of one trip and associated Short Notice Declaration (SND) events. The RAs have assumed that this is appropriate for a best new entrant peaker. This assumption results in a penalty payment of €40,044, based on the harmonised tariffs for AS, thus leading to a reduction in the value of AS revenue deducted from the ACPS.

The RAs are aware that the Ancillary Services Harmonisation may not be implemented until February 2010. The RAs carried out an analysis on the estimated revenue for the BNE Peaker in the month of January 2010, based on the old AS process. The RAs note that there is a minor difference (€0.01 per kW higher when using the old method) in the figures calculated for the old and new methods. The RAs have decided therefore to maintain the figures below which are based on the Ancillary Services Harmonisation calculations.

The SEMC have therefore decided that value of Ancillary Services that the BNE peaker for 2010 would achieve is €920,339. This equates to €4.84 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 Revenue			**960,383**
Penalties			40,044
Total (after penalties allocation)			**920,339**

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

12 DECISION ON 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 Infra Marginal Rent or Ancillary Services.

Cost Item (000's)	Northern Ireland Distillate
Annualised Cost per kW	85.58
Ancillary Services	4.84
Inframarginal Rent	0.00
BNE Cost per kW	**80.74**

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

13 CAPACITY REQUIREMENT FOR 2010

13.1 CAPACITY REQUIREMENT FOR 2010 FROM CONSULTATION PAPER

As detailed in the consultation paper, the methodology used for calculating the Capacity Requirement for 2010 is the same as that used in previous year's calculations. The RAs detailed the parameters settings used in the calculation of the Capacity Requirement. These include the Generation Security Standard, Demand Forecasts, Generator Capacity, Scheduled Outages, Forced Outage Probabilities and the treatment of wind. In addition, the RAs detailed the process used in calculating the Capacity Requirement, in conjunction with the TSOs.

13.2 RESPONSES TO THE CAPACITY REQUIREMENT FOR 2010

Eight respondents provided comments in relation to the Capacity Requirement Calculations. A number of respondents raised concerns on the lack of transparency in the calculation of the Capacity Requirement. They noted that although the assumptions used are documented, the lack of information on the input data used and the running of the CREEP (Adcal) model means that it is impossible for market participants to replicate the calculation process. More detail has been requested on the calculations.

A number of respondents raised concerns over the reserve margin when comparing the capacity requirement. One used the peak from the approved market modelling data published on the 3rd June 2009 (6799MW) and highlighted a reserve margin of just less than 0.5%.

In relation to the demand forecasts, one respondent welcomed the RAs and TSOs efforts to build up a view that includes the most-widely used economic forecasts for the two jurisdictions and the intention to revisit the forecasts with the most up to date information. Another respondent suggested that a review of the demand scenarios for the coming year will not add substance to the calculation and may just add uncertainty for participants seeking to forecast and understand their environment for the coming year. In general respondents acknowledged that the demand forecasts have reduced for the period in question. One respondent questioned why the capacity requirement had decreased by 7% when the demand forecast has decreased by 3.8%.

One respondent suggested that given the large degree of uncertainty and the unprecedented nature of the economic downturn, the Capacity Requirement calculation is re-calculated ex-post and with reconciliation of the Capacity Payments made to the market participants. One respondent proposed that a floor value should be introduced for the capacity requirement to help provide a medium to long term signal that the CPM is supposed to deliver

A number of respondents raised concerns in relation to the Force Outage Probability figure being used and suggested that it is too low in comparison to actual forced outage rates. They proposed that actual rates (averaged over a number of years) should be used rather than the 'target' value proposed in the consultation paper.

A number of respondents noted that the treatment of wind and the wind capacity credit calculation was not clear in the consultation paper and that the method used could result in the Capacity Requirement being understated.

13.3 UPDATE ON DEMAND FORECASTS & IMPACT ON CAPACITY REQUIREMENT FOR 2010

As highlighted in the consultation paper, the RAs decided to revisit the demand forecasts with the TSOs to determine if there is any need to change the forecasts based on the most up to date information. The update on the demand forecasts is below.

As a result of the discussions with EirGrid, the forecasts used in the consultation paper are the most accurate forecasts, based on the actual data available. It is therefore proposed that no change is made to the forecasts for the Republic of Ireland.

In the case of Northern Ireland when comparing the actual data with the forecasts, it appears that the forecasts used in the consultation paper were lower than the actual demand recorded. Therefore an adjustment has been made to the Northern Ireland forecasts to reflect this.

The resulting forecasts are detailed in the table below.

	2009 Forecasted Total Energy Requirement	2010 Forecasted Total Energy Requirement
Republic of Ireland	-3.8%	-0.9%
Northern Ireland	-2.6%	-0.0%

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 addition to the above, EirGrid provided an updated view of the wind that will be available on the system in 2010. There were as number of changes to the connection dates which resulted in the amount of wind being available increasing.

As a result of these changes, the half hourly data was updated and fed into the CREEP (Adcal) model. The Capacity requirement was then recalculated.

13.4 DECISION ON CAPACITY REQUIREMENT FOR 2010

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. The RAs will cover the following specific areas of concern raised in the CPM Medium Term Review:

- Improving the transparency of the calculation process
- Access to the Inputs used in the Capacity Requirement Calculation
- Running of the CREEP (Adcal Model)
- Forced Outage Probability
- Treatment of Wind and the Wind Capacity Credit used

As the query regarding the margin has also been raised in previous years, the RAs will also consider this concern within the context of the CPM Medium Term Review.

The RAs intend to hold a workshop with market participants in Q4/2009 to discuss the concerns raised on the method of calculation.

Based on the changes to the Northern Ireland Demand forecast and the increase in wind generation in the Republic of Ireland, the RAs worked with the TSOs in rerunning the Adcal model. All other inputs (FOP, SOD etc) were kept the same as the first run completed in the consultation paper. The second run of the Adcal model result in the Capacity Requirement reducing by 6MW to 6,826MW. The reduction is mainly due to the increase in the wind generation. The AdCal results are sensitive to the periods of least margin. Therefore it is probable that the wind generation increased during one of these periods, by more than the increase in Northern Ireland load causing the LOLE to drop and therefore also reducing the capacity requirement.

A number of participants have requested further information on the input used for the Adcal model. These are summarised in the table below.

Input	Description
Load Forecasts for ROI and NI for 2010	A combined load forecast for 2010, on a half hourly basis (17,520 data points) for both jurisdictions, was created and agreed with the TSOs. The base year used to develop this forecast was 2008. The demand assumptions above were used in developing this forecast. In addition, a wind trace for 2010 was also determined.
Generation Capacity	A list of all generation to be in place in 2010 was determined, including the Sent Out Capacity for each unit. For any units to be commissioned or decommissioned during 2010, the Capacity available was adjusted accordingly to reflect the actual period they are available (time weighted average). The Time-Weighted Capacity for Conventional Generation used in the Adcal model was **9206MW**
Wind Capacity Credit (WCC)	The most recent available Wind Capacity Credit (WCC) curve (produced by the TSOs) is used to assess the total WCC for the combined total wind installed. The Average WCC is calculated for the total installed wind. This average WCC is then applied to the time weighted total capacity for the Wind in the Market The Time Weighted Total Wind in 2010 used was 1,999MW. This results in a Capacity Credit of 0.178. The Time Weighted Market Wind Capacity in 2010 was 1,514MW. Therefore the Wind Capacity Credit is derived as **269MW** (1,514 x 0.178)

Scheduled Outages	The Scheduled Outage Durations are determined to the nearest number of weeks and are determined from the 5 year average of scheduled outages for each unit.
Force Outage Probability (FOP)	As highlighted in the consultation paper, the RAs maintained the value of **4.23%** for the FOP. It should be noted that an FOP of 0.19% was used for the Moyle Interconnect, again based on historical data.
Generation Security Standard (GSS)	As highlighted in the consultation paper, the RAs maintained the value of **8 hours** for the GSS.

Table 13.2 – *Summary of Inputs into Adcal Model*

As a result of the further analysis carried out in conjunction with the TSOs, the SEMC have determined that the Capacity Requirement for 2010 is **6,826MW.**

The Capacity Requirement for 2010 is 6,826MW

14 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 determined to be €551.1. The proposed figures are detailed in table 14.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2010	80.74	6,826	551,133,375

Table 14.1 – ACPS for the Trading Year 2010

The Annual Capacity Payments Sum (ACPS) for 2010 is €551.1M

15 APPENDIX 1 – RESPONSES TO SPECIFIC QUERIES RAISED TO CONSULTATION

Airtricity comments	Response
Summary - In general, Airtricity considered: "the consultation process and the analysis to be of sufficient rigour and in keeping with the established Capacity Payment Mechanism methodology". They welcomed the CPM Medium Term Review, in particularly the review of the Capacity Requirement.	No response required.

Bord Gais Energy comments	Response
Summary – BGE believes the RAs approach to the calculation of the BNE Fixed Cost and the resulting calculation of the Capacity Pot does not incentivise the type of plant that will benefit the SEM network in the long term. BGE consider the proposed changes in both the BNE Fixed Cost and the Capacity Pot counteract the objectives of the SEM arrangements. BGE asks that the RAs consider the implications of its proposals on the future of the market rather than on the short-term gains and highlight a number of areas where they query both the underlying methodology and assumptions.	It is acknowledged that the current structure of the capacity payment mechanism can create differing results year on year and cause changes in the size of the capacity payment. The RAs understand that concerns about volatility and have sought to address these through the consultation on the Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology (SEM-09-085)[5] and will continue to do so via the CPM medium-term review.
Stability and predictability of the underlying methodology - BGE believe the current methodology gives rise to a situation whereby the forecasted revenue streams of an investor can change considerably even during the 2-3 year construction period. Suggest that the methodology, its underlying costs and revenues, should remain constant for a period of years (possibly 5-6 years).	This issue will be given due consideration as part of the CPM medium term review.

[5] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?article=4be505c5-4157-4a70-95e5-7cd1524e42b3

Bord Gais Energy comments	**Response**
Cost vs. efficiency – BGE note an inherent difficulty in trying to design a methodology which is based on the decisions of a 'rational investor'. Given the expected lifetime of a generation plant, BGE is of the view that it is reasonable to assume that a 'rational investor' will seek to minimise its costs over the lifetime of the project and not solely at the time of construction. Accordingly, BGE does not believe that it is appropriate to prioritise cost over efficiency. BGE also believe a 'reasonable investor' would factor in that carbon prices are likely to increase over the life of the plant.	Please refer to section 4.3 above
Technology options - BGE do not disagree with the analysis of the technology options but had reservations and queries on a few specific areas. One, the 2009 paper presents the Alstom GT13E2 as an 180MW plant, yet the 2010 paper presents it as a 190MW plant. Two, the definition of a 'proven technology' as a technology where there are 3 examples of over 8,000 running hours. Three, the assumption that 'a rational investor' would allocate a larger weighting to cost rather than plant efficiency.	Please refer to section 4 above
Investment costs – BGE are broadly in agreement with the assumptions and calculations presented in the consultation but note that the 63% decrease in site procurement costs in one year highlights the need for the process to be stabilised and levelised over a number of years.	The site procurement cost estimate was informed by input from a property market specialist with energy sector experience.
Economic and financial parameters – BGE query the change in the economic plant life assumption and believe further consultation and an impact assessment should be completed before such an assumption is changed. Also query the ancillary services and infra marginal rent calculations.	See section 8 above for the response in respect of plant life. While the change in the life of the plant has a significant impact on results, it is one of a number of assumptions which have to be made in undertaking the BNE cost calculation. The RAs would question the proportionality of conducting an impact assessment when any assumption is changed. CEPA / PB have taken evidence from a range of actual generation investments and that evidence shows that equity investors in new build power plant are willing to invest on a 20 year basis. As noted in section 11 ancillary services estimates have been revisited through discussions with the system operators.

Bord Gais Networks comments	Response
Summary - Welcomed the fact the RAs considered both gas and distillate technology options. Note two queries with regards gas connection costs and the effect of electricity prices on the choice of plant.	The RAs have considered the comments in respect of gas connection costs. See Section 5.3 above.
Gas connection costs – BGN note that the Republic of Ireland duel fuelled plant gas connection cost estimates are the total costs of the connection. If the plant only has a 5% load factor, BGN note that based on connection policy the BNE would be subject to pay only 30% of the connection costs as opposed to the full connection costs.	The RAs have considered the comments in respect of gas connection costs. See Section 5.3 above.
Electricity prices - BGN ask the question whether the effect on electricity prices over the life of any new plant should be considered when determining the most appropriate plant. Assuming natural gas fired plants will generate electrical output at lower costs than distillate, then a natural gas fired plant would result in lower average electricity prices for the consumer and BGN feels this should be considered in determining the plant and its associated fuel choice.	The RAs note that the purpose of the calculation is to identify the costs of a rational investor. The RAs consider it unlikely that the investor would consider any element of social benefit and would focus on maximising private benefits.

Bord Na Mona comments	Response
Summary - BNM suggest there has been an improvement to the consultation process from last year but believe there remain elements of the process that are open to subjective changes from year to year. As a result, BNM believe the level of “regulatory risk” associated with the process remains high. BNM have a number of specific queries on parts of the consultation paper.	It is acknowledged that the current structure of the capacity payment mechanism can create differing results year on year and cause changes in the size of the capacity payment. The RAs understand that concerns about volatility and have sought to address these through the consultation on the Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology (SEM-09-085and will continue to do so via the CPM medium-term review.
Technology Selection - considered the technology selection process to have been organised in a more comprehensive manner with much broader range of	The RAs welcome the comments on the technology selection process. The RAs have clarified the plant output figures in annex 2 of the original CEPA

Bord Na Mona comments	Response
units considered than in previous years. Queried the Alstom GT13E2 fired on distillate, having an indicative power output of 190.1 MW over its lifetime when the same unit was selected in 2007 and had a notional lifetime net plant output of 182 MW. Commented on the risks and availability of an EPC contract from the GT manufacturer.	report and section 4.3 of this document. While the RAs acknowledge that there is a risk that the GT manufacturer may not take a project as the EPC contractor, the RAs do not consider that this would impact on the overall risk of the project given the presence of other potential contractors.
Capital costs - The discussion on the state of the EPC market is in line with BNM's recent experience in procurement of peaking plant. Overall, the estimation of the capital costs of the peaking plant has been significantly improved over last year's process, and the final figures give a reasonable estimate of the capital costs involved.	The RAs welcome the comment.
Unit output - Questioned the significant jump from the output determined for the same machine in the 2007 BNE assessment. BNM contends that the rational for this is increase is not justified.	The RAs have clarified the plant output figures in annex 2 of the original CEPA report and section 4.3 of this document.
Recurring costs - Main concern is with the significant swings in the line items and suggests that these items should be reasonably stable in the shorter term. BNM propose that line items should be adjusted year to year by an appropriate index or basket of indices. An issue that would be worth examining as part of the capacity payment mechanism review process.	This issue will be given due consideration as part of the CPM medium term review.
Financial parameters - The main discussion points arising in their analysis is the extension in the period over which the investment is recovered from 15 to 20 years, coupled to the level of the WACC which has been developed in the paper. Specific points are summarised in the table which follows.	The RAs welcome Bord Na Mona / NCB's comments on the financial parameters in the consultation paper but note that the choice of economic plant life and recommended range for WACC are based on extensive market evidence and the application of the CAPM framework. See Section 8 above for further detail.
Ancillary revenues - BNM note that there is no provision for AS penalties or other system charges, even though it is projected to collect a range of revenues across all of the reserve classes. Believe that some level of contingency should be allowed for penalty payments.	This has been noted by a number of the respondents. The RAs agree with the comment and have revisited the Ancillary figures in tandem with the TSOs. Updated figures are discussed in section 11 above

Bord Na Mona comments	Response
Capacity requirement - Concerned that capacity requirement has fallen by over 500 MW or over 7% of last year's figure.	The reduction is primarily due to the reduction in the Demand Forecasts. See Section 13 above.

Bord Na Mona report on financial parameters	Response
Summary - Bord na Móna has commissioned NCB Corporate Finance to give an independent assessment of the financial parameters in the Consultation paper, based on their recent experience of arranging finance for utility projects in Ireland.	Please see response in section 8 of this document.
WACC – The after tax cost of equity assumed for both Republic of Ireland and UK markets is in NCB Corporate Finance's opinion below the level that would be required to justify an investment decision in peaking plant under the current framework for cost recovery. NCB argue that the reduction in WACC, particularly the equity component, is surprising given the continued economic financial uncertainty.	In line with the majority of regulatory agencies in Ireland and the UK, CEPA / PB have adopted a building-block approach as the primary tool for estimating the notional BNE peaking plant's WACC. This includes employing CAPM as the primary tool for estimating the BNE plant's cost of equity. The RAs believe this is the most robust methodology for the purposes of estimating the cost of capital for a notional BNE peaking plant. While the RAs welcome the market evidence provided by NCB, overall, the RAs find there is no evidence to change the specific parameter assumptions used in the building block cost of capital estimate.
Cost of debt - Propose a real cost of debt of 5.60% and provide evidence of cost of debt for recent market issuances (for example ESB's recent UK Private Placement).	CEPA/PB (and the RAs) held discussions with banking contacts on the financing costs of similar types of investment in the UK and Ireland as a cross-check to the market evidence presented in their report. Market evidence on the range of the cost of debt in the UK and the Republic of Ireland is broadly in line with the range presented in the CEPA / PB report.

Bord Na Mona report on financial parameters	Response
Cost of equity – Propose a real after tax cost of equity of 10.0% or 11.38% depending on the assumption of the economic life of the plant. NCB note that the after tax cost of equity is a factor of risk free rate, tax rates, equity risk premium, asset beta and gearing. Consider each of the parameter assumptions to be conservative, and when taken together the resulting cost of equity to be very conservative.	CEPA/PB have considered regulatory precedent, market evidence and a broad range of academic studies on CAPM parameters as presented in their report. Based on discussions with banking contacts and their continued qualitative assessment of the non-diversifiable operational systematic risk of a BNE peaking plant, CEPA/PB continue to believe that their recommended range for the cost of equity remains appropriate. The RAs agree with this assessment.
Economic life of the plant – NCB argue that the arguments put forward by SEMC and CEPA/PB in relation to the extension of the economic life of the BNE has been made with limited reference to the type of plant, the dispatch regime and the regulatory context which applied to a peaking plant in the SEM. NCB argue that the increase in the economic life from 15 to 20 years increases the risk profile of the asset and this is not acknowledged in the consultation. As noted above, NCB provide two WACC estimates based on the assumed economic life of the BNE plant.	Please refer to section 8 above

Consumer Council comments	Response
Summary - The Consumer Council note that the Capacity Payment Mechanism has a significant impact on the final price of electricity and the RAs must seek to minimise this whilst balancing the business requirements of the electricity industry. Ask that in taking forward this work, the RAs ensure that the final outcome is fair and in the best interests of the consumer, and it looks to minimise any cost to consumers.	The RAs welcome responses by consumers and their advocates. The RAs also recognise the impact of the capacity payment mechanism on customer's bills and the need to ensure that the right balance between ensuring long-term security of supply (which minimises long-term costs to customer) and minimising short-term costs is struck. The RAs have robustly challenged CEPA/PBs calculations and recommendations in seeking to ensure this is the case.

Endesa Ireland Comments	Response
Summary - Endesa Ireland considers the costs related to the LTSA contract and the proposed “incentive” charges for Grid Code compliance should be included in the BNE calculations and that the plant life should be 15 years. In addition, Endesa Ireland strongly suggests that the RAs implement appropriate incentives to secure investment in smaller peaking units in locations that are beneficial to the system and a mechanism(s) for recovery of costs associated with connection to the gas transmission network and the dual-fuel requirement.	The RAs note that LTSA charges were included in the fixed maintenance component within the O&M costs. The second issue is captured in section 6.3 above
Costs - Endesa Ireland suggest that the costs that the RAs have included in the paper are within the same ballpark as the costs that Endesa Ireland has received from its vendors. Endesa Ireland considers the proposed costs that are accounted for in the BNE for 2010 for a unit to be located in Northern Ireland to be reasonable.	The RAs welcome the comment.
Economic life of the plant - Endesa Ireland does not consider it is appropriate to change the estimated life of the plant from 15 years to 20 years and does not consider the RAs have provided sufficient justification for this change.	Please refer to section 8 above
Missing cost items - Endesa Ireland would expect that a specific provision for LTSA costs is included in the BNE fixed costs. While ancillary service payments are taken into account, there is no provision for the cost of “incentives” for failure to meet the Grid Code Requirements.	The RAs note that LTSA charges were included in the fixed maintenance component within the O&M costs.
Unrecoverable cost items - Endesa Ireland has recently reviewed the costs associated with the dual-fuel requirements and has found these to be approximately €25 million. Endesa also note these are fixed costs, which are currently unrecoverable in the SEM.	Please refer to section 7.2 above

ESB International comments	Response
Summary – ESBI is concerned about the RAs' current proposal, because it reduces the capacity payment substantially from previous years. Consider it fails the criteria of providing financial certainty and should be a stable economical signal that encourages long term investments, and so it should not vary too much over the years. Believe that the current proposal does not agree with the capacity payment high level criteria, because it introduces volatility and financial risk and does not provide an incentive for investment in new plant and the availability of installed capacity. Also believe the current framework is not transparent and predictable.	These issues will be given due consideration as part of the CPM medium term review.
Technology - ESBi disagrees with the plant choice and considers that an aero derivative should have been selected. Suggest that the 20 minute start criteria be reviewed in light of renewable generation. Suggest a 10 minute start up as more appropriate. Note that the RAs' technology selection is also at odds with the technology proposed by EirGrid in the 2007 "fast build" consultation process. The fast build consultation suggested that the All Island Market (AIM) required multi-site aero-derivative engine installations for peaking purposes (ideally 3 x 60MW sites).	Please refer to section 4.3 above
Investment costs – ESBi believe that the assumptions under-state the costs significantly and would be insufficient to ensure the entry into the SEM of an actual best new entrant plant. ESBi considers that the 20,600m^2 site area as suggested is fitted to the footprint of the Alstom GT13E2, but that the estimated reduction of 63% in the price per m^2 compared with last year price is too aggressive. Also believe that site choice should be theoretical (and hence include similar allowances for water and gas costs to Republic of Ireland) rather than based on an individual site. ESBI question the viability of connecting a nominal 190MW plant to the 110KV system in Northern Ireland and are of the view that a 220KV	The RAs find it difficult to respond to this statement without support evidence. In particular, an understanding of ESBI's international benchmarking of O&M costs would be valuable. In respect of property, the RAs have commissioned an experienced property market expert to advise on site cost estimates. As set out in consultation, there are compelling reasons to suggest that Belfast West would be a credible site for a peaking plant. A theoretical site could have been used with appropriate assumptions determined for land and connection costs, however this would have increased the level of subjectivity in the process. The Electricity Connection costs are discussed in section 5.3 above options at

ESB International comments	Response
connection would be more realistic with a significant increase in costs. The 4 hour charging basis for gas transmission charges should be 8 hours (the value of GSS loss of load expectation per annum) and internal international benchmarking suggests O&M costs are understated.	the site with the TSOs who provided cost estimates. Please see the revisions to gas transmission charges in section 6.3.
Economic and financial parameters - ESBI agrees with the CAPM approach but should reflect actual financial conditions. Believe the assumptions on which the derivation is based should reflect current financial costs and conditions faced by generators in the Irish market. Do not agree with the following parameters: BNE investor is seeking to raise funding at the corporate level for the project; 60% gearing assumption; 10 years average tenor on the new debt; risk premium required by investors; cost of debt assumption. ESBi considers that a WACC of 6.80% and 7.13% considered in Republic of Ireland and Northern Ireland respectively are too low under current and likely future conditions and a value of WACC over 8.5% would be more realistic. Also question the change in the economic plant life.	The RAs welcome agreement on the CAPM approach. However, market evidence in the CEPA/PB report and discussions with banking contacts support the parameters used in the cost of capital estimate.
Ancillary services - Do not agree with subtracting AS revenues, want more detail of derivation of numbers.	This issue will be given due consideration as part of the CPM medium term review. Please refer to section 11 above for additional information on the Ancillary Services calculations.

ESB Power Generation comments	Response
Summary - ESB PG argue the decrease in the size of capacity pot represents an increase in regulatory risk, undermines investment and is not sufficiently reflected in the WACC. Query the change in the economic plant life and argue the BNE cost is 16% below ESB PG internal analysis.	See main body of report for responses to these queries.
Technology options and costs - ESB PG claim to have done a similar exercise in recent months. EPC costs were higher by a factor of one third. Concerned	The RAs note the point on emissions level proposed in the draft IED. However, given that the document has not been finalised and in light of the

ESB Power Generation comments	Response
that IED emissions levels were not reflected in the consultation document.	low running hours of the plant, the RAs do not consider that the revised emissions levels would have a material impact.
Economic and financial parameters – ESB PG believe an IPP investor should be considered, noting many new investors are IPPs. Question the gearing assumption on this basis. Also argue that financing for the plant could only be structured around a 15 year plant life. LTSAs not available for 20 years. Argue that the risk-free rate is understated and 3.5% debt premium is too low for an IPP investor. Equity risk assumptions understate the risks facing a BNE investment. ESB PG believes the equity risk premium should be higher and the beta is overstated.	Please refer to section 8 above.
Location - Consider that the plant would be in Republic of Ireland because of the Gate 3 queue.	The methodology required the RAs to consider the costs of a plant in Northern Ireland and the Republic of Ireland on a largely theoretical basis. However the RAs did discuss the feasibility of alternative locations with TSOs and have no reason to believe that the sites chosen are inappropriate.
Infra-marginal rent - Agree with the use of zero infra-marginal rent.	No response required
Ancillary services revenue - Dispute the use of a methodology which is not yet in place and consider this brings additional uncertainty. Figure is an order of magnitude higher than amount quoted in a recent consultation.	This has been noted by a number of the respondents. The RAs agree with the comment and have revisited the Ancillary figures in tandem with the TSOs. Updated figures are discussed in section 11 above.

Irish Wind Energy Association Comments	Response
Summary – The IWEA query the change in the economic plant life. Also note that the average rated output for the BNE is now 10MW greater than in previous years and 100% availability is assumed whereas in previous year availability was assumed as being 95%.	Please refer to section 8 and Section 4.3 above

Joint Development Agency comments	Response
Summary – The Joint Development Agency are Forfás, IDA Ireland and Enterprise Ireland. They are note that capacity payments must be sufficient to incentivise generators to make capacity available even when it is not dispatched and to provide a support mechanism to invest in new, more efficient generation plant. The Joint Development Agency expected the BNE cost to have fallen by more than the proposed reduction of eight percent given the continued decline in capital costs internationally and the proposal to increase the plant life from 15 years in 2009 to 20 years in 2010. The agencies recommend that the regulators revisit the cost assumptions, particularly for capital costs and indicate in their decision document what percentage of the fall in the BNE price is due to expanding the plant lifespan from 15 to 20 years. The agencies believe it is important that the CPM is kept under review to ensure it is delivering on its longer term objectives.	The RAs welcome responses by consumers and their advocates. The RAs also recognise the impact of the capacity payment mechanism on customer's bills and the need to ensure that the right balance between ensuring long-term security of supply (which minimises long-term costs to customer) and minimising short-term costs in struck. The RAs have robustly challenged CEPA/PBs calculations and recommendations in seeking to ensure this is the case. The RAs also note that our cost estimates were informed by discussions with manufacturers and O&M contractors and PB's extensive market experience. The RAs note that Endesa considered cost estimates to be credible while significant numbers of other parties with generation interests criticised them as too low. The JDA is correct that the change in plant life is a significant driver of year on year falls in the capacity price, representing approximately a 11% reduction. However, as outlined in the body of this document, the RAs consider that there is considerable evidence to support this change. The medium-term review will ensure the CPM is kept under review.

NIE Energy Supply comments	Response
Summary - NIEES is generally supportive of the approach taken to calculating the fixed cost of a best new entrant peaking plant for 2010.	The RAs welcome the comment.

NIE Power Procurement comments	Response
Summary - Note the volatility, reduction in pot year on year (compounded by more generation capacity) and fall in capacity requirement. More generally consider some costs to be understated, though recognise there may have been some falls from previous years. Believe the WACCs proposed are too low and do not reflect the current cost of equity.	The issue of volatility and the Capacity Requirement will be given due consideration in the CPM Medium Term review. The RAs believe it would be useful to understand the basis of concerns about the understatement of costs in more detail and evidence to suggest the use of a higher cost of equity.
Technology options - Consider it is not clear why the size or particularly ramp rate of the plants is used in the selection criteria. Also question why the plant output has increased by 10MW year on year.	The selection criteria have been used for a number of years and were discussed and reviewed with the TSOs. Please see section 4.3 for comments on plant output.
Investment costs – NIE PPB would expect both the Northern Ireland and Republic of Ireland costs to be higher given many of the costs for a project in Ireland will be higher than in Great Britain e.g. transport costs, labour costs, accommodation costs (since more skilled labour may be imported). Query why the EPC costs would be the same regardless of location. Also believe the distillate only option should have higher EPC costs for larger storage and fuel handling facilities and also higher Initial Fuel Working Capital costs.	The RAs note that there has to be an element of proportionality in undertaking the calculation and note that it is not possible to undertake a bottom up cost assessment for every site. The multipliers applied to EPC cost estimates are based on confidential project costs, including from plant in the UK and RoI. Hence there is some reflection of cost increases. The RAs would be keen to receive evidence of areas where other costs are higher. An adjustment has been made in relation to the concern raised regarding fuel storage costs.
Recurring costs - Query why 2008/09 capacity charge rates for Northern Ireland are used when estimated 2009/10 rates were also published. Believe the business rates cost estimate for the Northern Ireland plants are slightly lower than are currently charged for generating units. Also question the assumption on gas capacity requirement (4 hours operation).	The gas capacity costs have been updated to reflect the most recent tariffs. Please see section 6.3 In relation to the business rates, the RAs would welcome evidence to support the estimate provided.
Economic and financial parameters – Query the change in economic plant life and believe that financing for a plant life greater than 15 years is unlikely to be achievable. Believe a gearing assumption of 60% is too high. Also question the consultation paper ancillary services revenues estimate.	Please refer to section 8 above

Premier Power comments	Response
Technology option – Premier Power query the rationale for the 195MW output assumption. Also believe it is not clear how the output power and efficiency degradation values were calculated.	Please see section 3.5 and appendix 2 to the consultation document.
Cost assumptions - Concur with the consultation paper statement that a decrease of gas turbine prices is unlikely. Query the GT Pro adjustment factor of 3.8% and consider this to be an arbitrary adjustment factor.	Please refer to section 4.3 for a discussion of multipliers.

Virtutility Comments	Response
Summary – Virtutility comment on one issue in the consultation document. Note that an AGU comprises numerous small-capacity, distribution-embedded diesel generators operating in export mode and therefore the aggregated capacity can be totally guaranteed.	Please refer to section 4.2 for a discussion on the AGUs.

Viridian Comments	Response
Summary – Viridian believe the capacity payment price to be artificially low and does not reconcile with the actual costs of building a BNE plant in the SEM. Concerned with the move from a 15 year to 20 year economic plant life as discussed further below.	It would be useful to understand the detailed reasons for this view and have access to any additional evidence.
Life assumptions – Viridian has serious concerns about the proposal to extend the plant life of the BNE from 15 to 20 years. Note that although technically it might be feasible to extend the plant life by five years this would increase the average output degradation and incur other technology costs and regulations. Viridian argues that plant life should coincide with financing tenure which is fifteen years at best and typically shorter.	See Section 8.3.2 for responses to these queries.

Viridian Comments	**Response**
Outages – Viridian argue that BNE planned and unplanned outages need to be allowed for in calculating income per kW available. Note that in previous years it was assumed that planned outages of 13 days are typical and a forced outage rate of 2% was applied.	The RAs have reviewed previous year's calculations and note that no provision was made for outages in any area other than Plexos modelling. Outage values were specified when running the Plexos model to derive this calculation. Please refer to section 10
Cost of capital – Viridian argue that the WACC assumed in the calculation does not reflect the current or projected future conditions in financial markers. Consider it illogical that the WACC proposed provides a reduction of 0.9% and 0.3% for Northern Ireland and Republic of Ireland respectively. Largely concur with the calculation of the cost of debt but query the calculation of the cost of equity. Believe a BNE investor without the asset backing of regulated assets is likely to see gearing levels of 50% in future financings.	See main report response. CEPA / PB have employed CAPM as the primary tool for estimating the BNE plant's cost of equity. This is the approach widely employed by regulatory agencies in the UK and Ireland.
Location - Viridian question the approach of choosing the cheapest jurisdiction in an all island market. Believe a better approach would be to choose a mid-point between the BNE price in Republic of Ireland and Northern Ireland.	Please refer to section 7.1.2
Exchange rate - Viridian argue is unjustified.	CEPA /PB used the spot rate at the time when the document was developed, which the RAs note has now changed. The RAs recognise the challenges of forecasting an exchange rate going forward and consider this assumption to be justified
Specific cost items – Viridian argue that distillate and water storage costs do not account for commercial stocks of at least another ½ date supply which any peaker would hold to maintain availability above the strategic stock level. Believe fuel stocks and water should rationally include an uplift of 16.7% and the tank size and associate costs up scaled accordingly. Also question the cost of water connection being zero for Belfast West site.	Please see responses in section 5.2.6.

Viridian Comments	Response
Ancillary services revenues – Argue against deduction of infra marginal rent from the BNE price and would welcome further information on the assumptions used in the calculating ancillary services revenue for the BNE OCGT. Believe the revenue in the consultation paper is based on an unrealistic assumption that the plant incurs no penal performance incentives.	This has been noted by a number of the respondents. The RAs agree with the comment and have revisited the Ancillary figures in tandem with the TSOs. Updated figures are discussed in section 11 above. This issue will also be given due consideration as part of the CPM medium term review.
Site procurement costs – Note that site procurement costs have fallen by 63% and believe that this reduction seems excessive even in current market conditions.	The RAs have commissioned an experienced property market expert to advise on site cost estimates.