Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement & Annual Capacity Payment Sum for the Calendar Year 2012

Decision Paper

2nd August 2011

AIP/SEM/11/059

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2 SUMMARY OF DECISIONS

The Best New Entrant (BNE) Peaking Plant for 2012 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 **€76.34/kW/year.**

The Capacity Requirement for 2012 is **6,918MW.**

The product of these price and quantity elements yields an Annual Capacity Payment Sum (ACPS) for the 2012 Trading Year of **€ 528,120,120**

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 2011' (SEM-10-034))[1] , the following items have been reviewed and changed in calculating the final annualised fixed cost of the BNE Peaker:

1) The Exchange rate and Oil price have been updated to the most up-to date figures (cut off date was the model was Monday June 27th 2011).

2) The EPC Costs have been updated with a 0.73% increase to facilitate additional requirements for developing an adapted/specific generator design for Irish Grid Code compliance.

3) The Debt premium has increased from 1.75% to 2.00% which increases the Cost of debt. The UK pre-tax WACC increases from 6.26% to 6.41%, while the ROI WACC increases from 9.59% to 9.74%.

4) The Capacity Requirement has been updated to reflect an update to the Northern Ireland connection dates of wind generation available in 2012 resulting in a decrease of 24MW to 6,918MW.

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

Cost Item	Consultation Paper	Decision Paper	Variance
EPC Costs	87,037,000	87,672,370	635,370
Site Procurement	1,451,532	1,439,000	-12,532
Electrical connection Costs	7,720,000	7,720,000	0
Gas connection	0	0	0
Water connection	0	0	0
Owners Contingency	4,525,924	4,558,963	33,039
Financing Costs	1,740,740	1,753,447	12,707

[1] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=ab764619-7dee-4b19-afb2-d38b728bcfd4

Interest During Construction	1,815,350	1,960,840	145,490
Construction Insurance	783,333	789,051	5,718
Initial Fuel working capital	4,413,073	4,720,127	307,054
Other non EPC Costs	7,833,330	7,890,513	57,183
Accession & Participation Fees	3,903	3,903	0
Total	**117,324,185**	**118,508,216**	**1,184,031**
Cost Item	**Consultation Paper**	**Decision Paper**	**Variance**
Transmission & Market operator charges	677,088	671,420	-5,668
Gas Transmission Charges	0	0	0
Operation and maintenance costs	1,791,000	1,791,000	0
Insurance	1,392,592	1,402,758	10,166
Business Rates	631,479	626,027	-5,452
Fuel working capital	276,354	302,662	26,308
Total	**4,768,513**	**4,793,867**	**25,354**
Cost Item	**Consultation Paper**	**Decision Paper**	**Variance**
Investment Cost (excl Fuel Working Capital	112,911	113,788	877
Initial Working Capital (including Fuel)	6,665	7,077	412
Residual Value for Land & Fuel	-1,740	-1,777	-37
Total Capital Costs	**117,835**	**119,088**	**1,253**
WACC	6.26%	6.41%	0
Plant Life (years)	20	20	0
Annualised Capex	10,493	10,733	240
Recurring Cost	4,769	4,794	25
Total Annual Cost	**15,262**	**15,527**	**265**
Capacity (MW)	192.5	192.5	192.5
Annualised Cost per kW	**79.28**	**80.66**	**1.38**
ACPS	**Consultation Paper**	**Decision Paper**	**Variance**
Annualised Cost per kW	79.28	80.66	1.38
Ancillary Services	4.41	4.32	-0.09
Inframarginal Rent	0.00	0.00	0.00
BNE Cost per kW	**74.87**	**76.34**	**1.46**

Table 2.1 – *Comparison of Costs for Alstom GT13E2 in Consultation and Decision Papers.*

3 INTRODUCTION

On 6th May 2011 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 2012' (SEM-11-025[2]). 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 2012. CEPA and PB also assisted the RAs in the review of the responses to the consultation paper.

The RAs received 12 responses to the consultation (SEM-11-025). These are published along with this paper. Responses were received from the following parties:

- AES
- Bord Gais Energy
- Bord na Mona
- Endesa Ireland
- ESB PG
- Irish Wind Energy Association (IWEA)
- National Electricity Association of Ireland (NEAI)
- Power Procurement Business (PPB)
- SSE Renewables
- Synergen Power Ltd
- The Consumer Council
- Viridian Energy Limited

The responses provided were fully assessed and considered by the RAs and their consultants in the determination of the decisions laid out in this paper. In addition, discussions were held with concerned parties which also involve conference calls with the RAs consultants. 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 2012.

The 2012 Capacity Requirement has been calculated using the same methodology that has been employed in previous years. This paper also contains the data sheets used in the Adcal[3] calculation as a series of appendices.

[2] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=a6ac980b-67cc-4f29-a786-a40ae5f7d28f

[3] The iterative Adcal (CREEP) software is used by the TSOs to calculate the 2012 Capacity Requirement.

4 TECHNOLOGY OPTIONS

4.1 TECHNOLOGY OPTIONS FROM CONSULTATION PAPER

In the consultation paper (SEM-11-025) 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 5 options. From these a screening curve analysis was completed resulting on a final proposal. The proposed technology option for the BNE Peaker 2012 is the **Alstom GT13E2.**

4.2 RESPONSES TO TECHNOLOGY OPTIONS

Three 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 Technology section was completed in line with last years process. The main areas where concerns were raised were:

- Technology Choice
- Unit Output
- Plant Life

The specific comments relating to these areas are discussed below.

4.2.1 TECHNOLOGY CHOICE

Most respondents either agreed with or did not specifically comment on the proposed choice of Technology for the 2012 BNE Peaker.

Bord Gáis Energy had a couple of specific comments with respect to the technology choice, they commented that one of the primary objectives of the CPM is to signal suitable investment in the market and that the calculation did not signal the future need for flexible and fast responding back up generation. Bord Gáis Energy further outlined that the Alstom GT13E2 would be less suitable in a system with high penetration of intermittent generation.

They stated that the 2012 paper presents the Alstom GT13E2 as a 193.9MW gas plant, yet Alstom advertise the GT13E2 as producing output of 184.5MW1? and General Electric advertises its LMS100PA gas turbine as having an output of 103.045 MW2 which is in conflict with the figures presented by the RAs in its paper. In acknowledging that gas turbine performance varies with location and ambient conditions, it is unclear from reviewing the RAs consultation documentation what weather conditions the RAs have assumed in their analysis. In BG Energy's view, it is best practice when comparing gas turbine output and performance to benchmark against ISO standard conditions3. BG Energy therefore asks that the assumptions and rationale for changes in the assumptions are outlined and substantiated as part of the decision paper.

They further stated than, BG Energy does not agree with the RA's preferred technology type and they also stated that, the chosen BNE has a ramp rate of 20 minutes. This will not be technically optimal as peaker plant will be required to respond more rapidly than they are currently given the expected future generation mix.

Endesa Ireland commented on the installed capacity of the proposed BNE, stating it is too large. Given the expected increase in the penetration of renewables needed to meet the 2020 targets, it would be more advantageous from a system point of view for smaller units be constructed in areas near wind farms. They also commented on the environmental standards and community impact of the unit in its specific location and questioned the reasoning behind the Interconnector being deemed an unsuitable technology choice for the BNE.

4.2.2 UNIT OUTPUT

PPB had also stated that No investor has chosen the Alstom GT13E2 and ESB stated that the RAs consistently choose the Alstom GT13E2 but no actual market participants have done so.

4.2.3 FUEL CHOICE

Endesa Ireland considered that another matter of concern is that the choice of distillate as the chosen fuel type means that gas connection costs are not recoverable in the SEM. They stated that there has been a gap in the SEM since its establishment and it should be resolved urgently, especially in view of the fact that gas units will be key, in catering for the intermittent nature of wind. These costs may be absorbed by baseload CCGTs who have historically benefited from infra-marginal rent, but this may not continue into the future and certainly will not be the case for peaking units.

Further, the selection of distillate as the preferred fuel will result in additional costs being incurred in planning permission and IPPC licence processes which should be included in the BNE fixed costs. (“As stated previously, NIAUR have indicated that any unit to be constructed on one of the land bank sites must be “consistent with energy policy”.)

4.2.4 PLANT LIFE

As with last year, several respondents discussed the plant life assumption of 20 years. Respondents highlighted their support for returning the plant life assumption back to 15 years from the current 20 years.

4.3 DECISION ON TECHNOLOGY OPTION

Regarding the Technology choice, in the process of developing the consultation document the RAs and CEPA/PB consulted 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.

With reference to the BG Energy's comments on the GT13E2's output and the GE Published figures, water injection increases the GT13E2's output (Refer to Annex 2 of 12 June 2009 CEPA/PB report[4]). GE's website figures exclude inlet/outlet draft losses and do not state whether net or gross power is being expressed. The ambient conditions used are stated in Section 3.5.1 of CEPA/PB report. ISO conditions do not reflect average Irish conditions, nor the conditions at which generator's plant capabilities are stated.

In response to the plant size, the comments on the size of the plant may be valid as a matter of long-run energy strategy; however, the RAs feel that the GT13E2 remains appropriate as it can meet the TSO's technical criteria. The onus is on the TSOs and the market to dictate a smaller peaking plant for the process if appropriate.

In response to statements that the Alstom GT13E2 has not been selected by any market participant the BNE peakers is not intended to be the market's BNE, but the most economical BNE (and consequently one which takes into account the infra-marginal rent and AS payments within the methodology's calculation).

The RAs agree that ensuring the BNE plant is compliant with relevant emissions legislation is an important determinant of plant choice. Within the criteria used to filter candidate plants, compliance with relevant environmental legislation was specifically considered as a pass/fail criterion. Even during the long-listing stage, generally only plants with known low NOx capability were selected. In many cases, the gas turbine costs for the Dry Low NOx/Emissions option is indeed more expensive than the standard combustor option (where available) and these higher costs were carried right the way through the entire process. The RAs therefore consider that each shortlisted plant would be expected to meet the requirements of relevant legislation. Respondents also should bear in mind that the environmental impact of the selected BNE plant will be minimal as the intention is for the BNE plant to be last on the merit order.

With regard to plant life the RAs continue to believe a 20 year economic life is a prudent and balanced view for a peaking plant in the SEM based on a wide range of evidence that was reviewed during our 2010 report.

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 and manufacturing OEMs; 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.

[4] http://www.allislandproject.org/GetAttachment.aspx?id=61178f7d-e14a-4001-88a7-cf34c76a2a9d

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 2012. Therefore the SEM Committee have decided that the BNE Peaker for 2012 is the Alstom GT13E2. The Unit output of this plant is 192.5MW

The Technology Option for the BNE Peaker 2012 is the Alstom GT13E2

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

Three 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.

The main areas where concerns were raised were:

- EPC Costs
- Site Procurement costs
- Electrical Connection costs
- Initial Fuel Working Capital
- Other Costs

The specific comments relating to these areas are discussed below.

5.2.1 EPC COSTS

A further criticism that was made of the choice of plant was that the unit was not Grid code compliant, this was highlighted by Endesa Ireland, Bord na Mona, and ESB PG. They suggested that it is not clear whether the unit can operate at full leading 0.93 at Registered Capacity and similarly, when operating at this range whether it can fault ride through for 200ms, which is the Grid Code requirement. Respondents requested clarification on these points and argued strongly that the BNE should meet all Grid Code requirements or the costs ensuring Grid Code compliance included in the BNE price.

Bord na Mona commented that it is not sufficient to assume that the BNE plant will be grid code compliant 'out of the box' without properly addressing the potential costs associated with achieving compliance.

5.2.2 SITE PROCUREMENT COSTS

NIE PPB offered comments regarding the Residual value of land and fuel. They questioned why there would be such a large difference between NI and ROI for this matter

5.2.3 ELECTRICAL CONNECTION COSTS

One respondent stated that the electrical connection costs proposed in Section 6.3 seem to be low, given Endesa Ireland's experience, although this is difficult to analyse without greater detail; they have only been told that the connection would be at 110kV.

5.2.4 INITIAL FUEL WORKING CAPITAL

PPB discussed Initial Fuel Working Capital costs; they stated that the paper determines the initial working capital requirements to fund the purchase of fuel stocks. However, it is not clear why the cost is the same in Northern Ireland as in RoI. Distillate in Northern Ireland attracts Excise Duty that is payable when purchased although it can be reclaimed when consumed to generate electricity. Hence the Duty is a cost that initially must be funded. The current rate is 11.14pence/litre which equates to over £133/tonne.

5.2.5 OTHER NON EPC COSTS

One respondent considered that the costs of obtaining planning permission and environmental permits, including environmental studies (e.g., EIS or Appropriate Assessment), should be included with site procurement costs, to fully reflect costs incurred.

ESB PG queried the EPC cost estimates made for the consultation papers. CEPA/PB estimated that EPC costs accumulate to €87m based on GTPro version 20, however ESB PG compared this to the results of the GTPro model (version 21) and suggested that EPC costs are in the region of €95m.

Endesa Ireland proposes that, rather than choosing a theoretical site, as in Section 6.2, the RAs should base cost estimates on actual consented sites on the island. An average of individual cost components associated with these plants, rather than estimations could then be used. Endesa Ireland also stated that a rational investor would take into account the taxation regimes in each potential location prior to selecting a site – including how they would apply to energy and capacity payment income for the life of the unit. Given the more favourable tax rates in Ireland, evidence shows a rational investor would choose to locate their plant in Ireland.

Endesa Ireland also commented that the UR consulted in May 2010 on the question of what should be done with NIE Land Bank sites, including the West Belfast site. In February 2011 the UR published a note which indicated that a request for proposals and criteria for selection will be issued, and directing NIAUR to appoint an agent to act on their behalf. On this basis, the site is not currently available to the market so a generator could not currently develop a BNE on the site – it is thus argued not to be a feasible site for a BNE to enter the SEM in 2012.

Endesa Ireland also argued that the cost of fuel tanks for a distillate plant should be included in the investment costs. This is akin to gas connection costs for a dual fuelled station. Endesa Ireland estimate that this cost would be in the region of Eur 800,000-1,000,000 but propose that the RAs further research this question. Provision for the construction of the tank and provisions for compliance with the Seveso requirements should also be included in EPC costs.

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. When considering the EPC cost for the plant, the same process as last year was used. The RAs along with CEPA/PB have completed the BNE calculation consistent with the methodology developed at the inception of the SEM. The investment is notional and therefore may differ from what is actually observed in the market.

Several respondents commented on the exclusion of capital costs associated with grid code compliance, the RAs have worked with CEPA/PB and the manufacturing OEMs. Alstom have confirmed that in the past they have developed an adapted/specific generator design for a grid code compliant power plant in Ireland. PB considers that Irish Grid Code compliance, particularly in terms of leading power factor capability, is expected to be less onerous for smaller units, such as the GT13E2, than for those employed at the new Aghada CCGT plant in Ireland that utilises an Alstom gas turbine generator.

The difficulty in quantifying any additional cost for the electrical generator on account of Irish Grid Code requirements for the BNE calculation is that each project case would need to be evaluated separately by the OEM/generator designer. Project/site specific elements such as Grid Short-Circuit Power, Grid External Reactance Value and Transformer Reactance Value would have to be determined for each site under consideration, and the consequential requirements for developing an adapted/specific generator design for Irish Grid Code compliance then carefully considered by the OEM/generator designer. The RA along with their consultants have considered the increase in generator cost and have determined that the impact there of on the EPC price is estimated to be a 0.73% increase. The RAs have scrutinised this aspect of the approach and are content that a rigorous assessment of these costs have been carried out by CEPA/PB.

The RAs agree with the responses that the most up to date information exchange rate should be included for the purpose of the calculation. Exchange rates vary over time due to a combination of economical factors, such as growth rates, interest rates and investor confidence. It is considered beyond the scope of the BNE calculation to assess movements in the €/£ exchange rate over the lifetime of the investment. In light of this the assumptions for the exchange rates have been updated, as well as the oil prices to the latest available. For exchange rates, the spot rate of £1= €1.1253 was sourced from www.oanda.com on 27 June 2011 (this has updated the €1.1351 rate used in the consultation paper). The RAs believe that a current spot rate is preferable to using an unknown future rate, as it provides greater certainty and transparency to participants.

The RAs also note the views of the respondents regarding using the most up to date information for the calculation and have updated the oil price used to use the ICE Brent price on Bloomberg as traded on Monday 27 June 2011 ($105.99)[5].

[5] http://tonto.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D

The RAs note the comment from Endesa Ireland regarding the estimates of electrical connection costs being to low. The CEPA / PB initial report provides more details in Section 4.3.5 and the RAs have used the same assumptions as last year.

Regarding PPB comments regarding the Residual value of land and fuel, as outlined in CEPA/PB's report, land values for the Belfast West site were presented as a capital value, taking account of both commercial/ industrial property land values in Belfast and the likely (capitalised) value of a lease. The RAs are of course aware that the Belfast West site would most likely be leased rather than acquired, for consistency with the RoI, the land costs are presented as a capital value. The approach taken to calculate site procurement costs means (notionally) there would be a residual value that could be realised in the market. In theory an alternative approach could be adopted whereby lease payments over the life of the plant were estimated. Given uncertainty over lease payments for the Belfast West site it is considered beyond the scope of the BNE calculation to determine in detail what these payments might be. In practice there would be expected to be very little difference (in terms of outturn cost) between the two approaches.

With regard to PPB comments on Initial Fuel Working Capital costs, the RAs having considered how the excise duty works in the UK, will consider the issue raised by the respondent to be valid. The fuel tax is indeed a fixed cost which would need to be funded by the BNE investor. It is proposed that the duty be added to BNE 2012 fuel cost (€/litre) assumed in the current version of the financial model. Research completed by CEPA/PB suggests the RoI does not have a similar excise duty that is applied to fuel used by electricity generators. This is a fixed investment cost, therefore, that applies solely to the NI BNE peaking plant.

The RAs also note the comment from Endesa regarding the potential revisions to the fuel security code in Northern Ireland, but consider that at the time of writing this report, the RAs have used the most up to date available information as these amendments have not yet been finalised and therefore will be continuing with the same assumptions as in previous years. The RAs can confirm that the fuel stock assumption remains at 3.5 days for the distillate plant.

In response to ESB PG query on the EPC cost estimates, the cost estimate multipliers within PEACE were increased for the Version 21, which was released after CEPA/PB submitted their report for the consultation paper. However, evidence of price increases in Europe in the last several months have not been observed in the market and thus an increase in cost estimates has not been deemed appropriate at this time.

In response to the assumptions for the change in other non-EPC costs and Investment costs which are based on CEPA and PB's experience, environment costs and Tank costs were included in EPC cost estimates section.

Endesa also commented that the Belfast West site is not currently available to the market so a generator could not develop on it. NIAUR did issued NIE with a direction to appoint an agent for the site. The Belfast West site has been cleared of the old power station. Preliminary evaluation of the area available at the Belfast West site has revealed that it is unlikely that a carbon capture ready (CCR) CCGT plant with two F-class GTs would be able to fit within the site. However, a CCR CCGT plant with a single GT could fit together with the proposed peaking plant. Therefore, the peaking plant represents a good option as part of a combined development at the site. The RAs continue to believe that Belfast West is a practical and available site for a BNE peaking plant.

In the absence of any other comments on the other Investment areas, 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 following table summarises all the investment cost for each jurisdiction and for each fuel type.

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
EPC Costs	88,840,838	88,798,532	87,712,662	87,672,370
Site Procurement Electrical connection Costs	759,849 6,930,000	767,262 6,930,000	1,425,097 7,720,000	1,439,000 7,720,000
Gas connection	3,620,000	0	1,810,000	0
Water connection	450,000	450,000	0	0
Owners Contingency	4,619,724	4,617,524	4,561,058	4,558,963
Financing Costs	1,776,817	1,775,971	1,754,253	1,753,447
Interest During Construction	4,079,806	3,950,135	1,990,937	1,960,840
Construction Insurance	799,568	799,187	789,414	789,051
Initial Fuel working capital	3,464,363	4,138,408	3,951,334	4,720,127
Other non EPC Costs	7,995,675	7,991,868	7,894,140	7,890,513
Accession & Participation Fees	3,903	3,903	3,903	3,903
Total	**123,340,542**	**120,222,789**	**119,612,798**	**118,508,216**

Table 5.3 – *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 Dual Fuel Plant. The table below compares the costs detailed in the consultation with what has been decided by the SEM Committee.

Cost Item	Consultation Paper	Decision Paper	Variance
EPC Costs	87,037,000	87,672,370	635,370
Site Procurement	1,451,532	1,439,000	-12,532
Electrical connection Costs	7,720,000	7,720,000	0
Gas connection	0	0	0
Water connection	0	0	0
Owners Contingency	4,525,924	4,558,963	33,039
Financing Costs	1,740,740	1,753,447	12,707
Interest During Construction	1,815,350	1,960,840	145,490
Construction Insurance	783,333	789,051	5,718
Initial Fuel working capital	4,413,073	4,720,127	307,054
Other non EPC Costs	7,833,330	7,890,513	57,183
Accession & Participation Fees	3,903	3,903	0
Total	**117,324,185**	**118,508,216**	**1,184,031**

Table 5.4 – *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:

- Transmission TUoS charges
- Gas Transmission Charges

6.2 RESPONSES TO RECURRING COSTS

Eight respondents provided comments in relation to the recurring costs detailed in the consultation paper

6.2.1 TRANSMISSION USE OF SYSTEM CHARGES (TUOS)

Nine respondents highlighted the proposed changes to the Generator Transmission use of system (GTUoS) charges.

NEAI noted that the assumed TUoS charge for a BNE is based on 2010 charges, whereas NEAI believes given the proposed change in methodology to apply from October, it would be more appropriate to utilise the indicative 2011/12 charges as the basis for the BNE. This will result in higher TUoS charges for NI based BNE but is likely to be more reflective of actual costs.

Several respondents also stated that the indicated generator TUoS in NI is significantly higher than that included in the BNE calculation and that these charges are generally higher in NI than in Ireland, further highlighting jurisdiction specific elements of the assessment.

Viridian noted significant changes to the indicative TUoS rates for 2012 as published in SEM-11-036 and would consider this a more appropriate predictor of future rates (that any rational investor would assume) than those currently used in the BNE calculation. They stated that it is therefore appropriate to use the indicative tariffs published in SEM-11-036 in calculating the cost of the BNE Peaker for 2012.

Indeed several respondents highlighted that these indicative rates would be taken into account by an investor and that the calculation should be adjusted to reflect this.

6.2.2 GAS TRANSMISSION COSTS

NIE Power Procurement Business noted that gas transportation tariffs used for Northern Ireland for 2011/12 are not the final rates; they understand that the actual gas consumption has been lower than previously forecast and therefore the estimated gas transportation charges for 2011/12 may be understated. The actual tariff for 2011/12 is scheduled to be published in August 2011.

They further questioned if the capacity calculation based on 4 hours of operation was prudent as gas nomination must be given as flat 1/24th profiles. It observed that under these assumptions gas could not be delivered to the plant without being subject to penalty charges or being restricted.

6.3 DECISION ON RECURRING COSTS

In previous years the RAs have based the assumptions in the consultation paper on the latest published information and if updated final tariffs /rates relating to the BNE year are available ahead of a decision on the cost of the ACPS, the values in the calculations will be adjusted accordingly to reflect these.

Regarding the comments about potential changes to TUoS charges, the SEM Committee decided on the tariff methodology in its decision paper “SEM-10-081 All-Island Generator Transmission Use of System Charges”. The Dynamic plus Postage Stamping methodology was chosen. Further details of the methodology can be found in the “SEM-09-107 Preferred Options to be considered for the Implementation of Locational Signals on the Island of Ireland” and “SEM-11-018 Locational Signals Project: All-Island Generator TUoS”. SEM-11-018 was formulated by the TSOs with input and advice from the RAs. It discussed and provided recommendations on a number of specific issues:

- Calculation methods for All-Island Generator TUoS Tariffs
- Fixed Tariff Options
- Non-Firm Generator TUoS
- Charging Distribution Connected Generators TUoS – Threshold Level

The RAs and the TSOs are currently independently reviewing the responses to SEM-11-018. The TSOs will consider whether to revise their recommendations based on the responses received. It should be noted that the RAs will also assess the recommendations advanced by the TSOs, in light of the responses received to SEM-11-018 and will decide whether they are the appropriate measures to implement. The intent is that a SEMC decision will be made on all these matters, including the indicatives, in a final decision paper by mid Sept 2011.

The TUoS charges quoted by the respondents are currently only indicative rates and they will be reviewed by the SEM Committee. In the view of this the SEMC recognises that the indicative rates do not provide a finalised estimate of the costs of a BNE plant entering the market in 2012. As no SEMC decision has been made, the SEMC do not feel it is appropriate to use the indicative TUoS rate as the indicative target rate has the potential to change and therefore could produce a subjunctive unrealistic ACPS which could be subject to criticism. It is therefore proposed that no change is made to the TUoS charges in the consultation paper.

With regards to the gas transmission charges, PPB suggests that figures to be published in August should be used. Given the ACPS decision will have been completed before this date the RAs propose the current rates continue to be used and therefore recommend that no changes are made.

The RAs understand that transportation charges may have in the past been understated, given Gas link “Code of Operations” paragraph 7.3.7, appears to require a peaking plant to book capacity for a minimum of 16/24 of its “maximum hourly quantity”. Accordingly they have changed the gas transmission charge calculation to assume that on a peak day the BNE plant would run for 16 hours rather than 4 hours. It should be noted that the change has no impact on the overall capacity pot as the distillate plant continues to be the selected fuel type in both jurisdictions.

The impact on BNE gas transmission costs is summarised in Table 6.1.

Jurisdiction	Cost per kWh [1]	Plant size (MW)	Efficiency (%)	Assumed hours run	Transmission charge
NI capacity	£0.32590	193.9	35.19%	16 hours [2]	€3,580,498
RoI (capacity)					
Onshore	€ 0.446809	193.9	35.19%	16 hours [2]	€6,469,485
Interconnection	€ 0.21583				

***Table 6.1:** Gas transmission charges - Note 1: Peak day capacity & Note 2: Per peak day*

In summary, the RAs have decided that there will be minimal changes to the recurring costs. The costs are summarised in the table below.

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
Transmission & Market operator charges	1,019,749	1,012,386	676,303	671,420
Gas Transmission Charges	6,469,485	0	3,580,498	0
Operation and maintenance costs	1,816,000	1,791,000	1,816,000	1,791,000
Insurance	1,421,453	1,420,777	1,403,403	1,402,758
Business Rates	1,518,278	1,507,316	630,580	626,027
Fuel working capital	337,231	402,844	253,366	302,662
Total	**12,582,197**	**6,134,323**	**8,360,150**	**4,793,867**

Table 6.2 – *Summary of Recurring Costs for BNE Peaker for 2012*

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. The following table compares the costs detailed in the consultation with what has been decided by the SEM Committee.

Recurring Cost	Consultation Paper	Decision Paper	Variance
Transmission & Market operator charges	677,088	671,420	-5,668
Gas Transmission Charges	0	0	0
Operation and maintenance costs	1,791,000	1,791,000	0
Insurance	1,392,592	1,402,758	10,166
Business Rates	631,479	626,027	-5,452
Fuel working capital	276,354	302,662	26,308
Total	**4,768,513**	**4,793,867**	**25,354**

Table 6.3 – *Comparison of Recurring Costs for Alstom GT13E2 in Consultation and Decision Papers.*

7 ECONOMIC & FINANCIAL PARAMETERS

7.1 ECONOMIC & FINANCIAL PARAMETERS FROM CONSULTATION PAPER

In the consultation paper and the CEPA report (Appendix 3 of ('Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2011' (SEM-10-034))[6]), 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 BNE economic and financial parameters included in the RAs consultation were:

- a reasonable estimate for the gearing of the BNE is 60% as employed by the RAs for 2009 and 2010;
- the economic plant life for the BNE will be 20 years as employed by the RAs for 2009 and 2010;
- the appropriate range for the BNE cost of debt is 5.5%-9.0% in the RoI and 3.0%-4.0% in the UK;
- the appropriate range for the BNE cost of equity is 9.4%-13.5% in the RoI and 6.9%-8.5% in the UK.

The sections which follow consider specific respondent comments on BNE economic and financial parameters.

7.2 RESPONSES TO ECONOMIC & FINANCIAL PARAMETERS

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

- Credit rating
- Cost of Debt
- Cost of Equity

These are discussed further below.

7.2.1 CREDIT RATING

Several respondents commented on the assumptions surrounding the BNE credit rating. The consultation paper assumed that the BNE investor is an integrated utility with a BBB credit rating. Endesa Ireland suggested that this discriminates against smaller market participants and suggested that a rational investor was not necessarily an international utility; a point also raised by ESB PG.

[6] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=ab764619-7dee-4b19-afb2-d38b728bcfd4

7.2.2 COST OF DEBT

Several parties noted that the proposed cost of debt is too low and does not reflect 'realities faced by participants'. As an example of this, a number of respondents highlighted the NIE Energy bond issue in late May (after the publication on the consultation documents) which had an initial yield of 6.39%.

Viridian commented that the regulators have proposed a debt premium of 175bp for NI that does not appropriately account for existing traded premiums on NI regulated assets. Such as the NIE Bond that was recently issued and that trades at a premium of 250bp. They provided some supporting evidence in the form of a case study.

7.2.3 COST OF EQUITY

Several respondents commented on the specific parameters used in the CAPM model to the derive the BNE cost of equity. Several respondents stated that the cost of equity was too low in both jurisdictions.

BGE highlighted that the betas used in the consultation are benchmarked against betas for determinations for regulated monopoly network assets. BGE argued a BNE generator merited a much higher beta given its operation in a competitive electricity market with higher business and cashflow risk. They recommend a beta of 1.5.

ESB PG also questioned the beta used, suggesting that from their own research of comparator organisations, an unlevered beta of 0.7 should be used, rather than the 0.55 assumed in the consultation paper.

A number of comments were also made by respondents on the Equity Risk Premium (ERP) which was considered to be too low by respondents who commented on this issue. One respondent suggested that precedent from the ESB/EirGrid T&D 2011-2015 price control suggested an ERP closer to 5% was appropriate. Viridian commented that since investors have access to investment opportunities globally, a global equity risk premium should be used. They recommend using an ERP of 5.20%.

7.2.4 SINGLE ELECTRICITY WACC

The determination of an appropriate WACC is a key factor in the calculation of the annual BNE fixed costs. There was the view of a number of respondents that it is inappropriate to treat WACC in RoI separate from WACC in NI (based on generic UK fundamentals).

Synergen did not believe the assessment of the NI WACC was prudent, and that a number of elements of the WACC treatment are inappropriate given the assumed nature of the investment and the cross-jurisdictional nature of the SEM, including common market arrangements and a common regulatory regime. For example, a generator located in NI has the same exposure to a supplier default in the RoI as is faced by a generator in the RoI. They stated that

1. Within SEM-11-025, the WACC assumptions are locational based on country specific assumptions. However, the required returns are higher NI compared to the rest of the UK given the region's risk profile, as noted in a current British Government consultation which states "… it is clear Northern Ireland faces a

greater challenge than most other parts of the UK in competing in a global market, and attracting investment to grow the private sector and drive economic growth."

2. Whilst the cost of debt may (theoretically) be considered on a jurisdictional basis, and for a network business this may be realistic. However, for a generation entity its risks and rewards are market wide as the SEM operates on the basis of common market and regulatory arrangements across jurisdictions.

3. The assumed level of required reward appears unrealistically low given the interest rate for recent NIE bonds (May 2011) was 6.375%. Clearly a merchant BNE would have a higher cost of borrowing compared to a network related business owned by the Irish Government.

Synergen thus believes that the wide differences in risk free rates between jurisdictions are not realistic in considering the BNE Peaker.

NEAI stated that the determination of an appropriate WACC is a key factor in the calculation of the annual BNE Peaker. It is the NEAI's considered view that it is inappropriate to treat WACC in RoI separate from WACC in NI (based on generic GB fundamentals). They stated that the fact of the matter is that an investor is investing in SEM, which is a single market, and a investor risk premium should therefore be more reflective of the risks of investing in SEM (RoI and NI) and the WACC should reflect this. They proposed that this is a more sensible approach to choosing a GB based risk and cost of debt/equity profile which bares no relevance to costs of investing in SEM.

7.2.5 OTHER ISSUES

Overall, Endesa Ireland requested that the RAs identify a source for the inputs to the WACC calculation that will be utilised in future BNE calculations. Another comment that was raised by BGE, Endesa Ireland and IWEA suggested that the risk-free rate was too low at 1.75%, if inflation is approximately 2%. It was argued this implied a negative risk-free rate.

7.3 DECISION ON ECONOMIC & FINANCIAL PARAMETERS

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

There were ten responses in relation to the WACC parameters. 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 main areas of concern were in relation to cost of debt and cost of equity. The RAs would like to thank respondents who provided evidence to present to the RAs or CEPA.

7.3.1 CREDIT RATING

The RAs and their consultants continue to believe the BNE investor is likely to be an integrated utility seeking to raise funding at the corporate level. In the analysis of market data, data for BBB grade debt was employed, which is a more conservative assumption and consider appropriate for the type of investor assumed in the BNE calculation methodology. Therefore no change to the calculation assumptions is proposed.

7.3.2 COST OF DEBT

A number of respondents argue that the assumed cost of debt for the BNE plant is unrealistically low given the coupon rate for a recent issued NIE bond. This bond was issued on the 27th of May and has a coupon on 6.38%, and a current yield to maturity of 6.39. A number of respondents presented this as evidence to support a premium on the cost of debt for an integrated utility (the expected investor in the BNE) based on the Island of Ireland and a participant in the SEM. Respondents argued that these factors needed to be factored into the BNE calculation for 2012.

As part of the analysis CEPA compared the yields for a number of BBB+ rated bonds for the UK including the recently issued bond by NIE. The Bonds looked at include London Power, South E Power, NIE Finance, Aviva Plc, Brambles Finance, Ensco Plc and Experian Finance.

The evidence presented to the RAs illustrates a higher yield on NIE debt compared, for example, bonds for distribution network businesses recently sold by EDF. The yield on the NIE bond is nearly 70bps higher than that on the South East Power bond.

There are a number of characteristics of the NIE bond which might be considered drivers of this high coupon rate, which are individual to this issue, rather than necessarily evidence of investors requiring a premium for assets with a Northern Ireland connection.

As a benchmark and cross-check of the evidence, CEPA have considered evidence of debt costs for other utility companies in NI. They also compared information on a Phoenix Gas issued bond from 2009.

The evidence provide would seem to support an increase in the range for the BNE WACC, which on balance should be an additional 50bps on the top end of the range for the debt premium, for NI and the RoI.

7.3.3 COST OF EQUITY

The RAs do not propose to change the cost of equity range for either the UK or the RoI BNE WACC. The respondents did not provide sufficient evidence to support their arguments that the parameters assumed in the consultation paper result in to low an estimate of the BNE cost of equity. The RAs consider a range of 4.5% - 5.0% for the ERP to be representative of the medium and long term.

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 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.

As regards the beta assumption, CEPA/PB would like to highlight that the consultation paper uses an equity beta greater than 1. This implies that the investment is considered riskier than the market. The BNE beta is indeed higher than a regulated monopoly network asset and this is reflected in the assumptions used in the consultation paper.

7.3.4 SINGLE ELECTRICITY WACC

The responses raise an interesting issue - the circumstances of investing in a market that operates across two jurisdictions has relevance as it is the cash-flow risk of the investment which investors will in reality consider. The mechanism has followed a methodology employed since the inception of the SEM and the RAs believe it would be a major methodological change to the way the capacity payment mechanism has historically been set, were a single WACC approach adopted. The SEMC wish to remain with the current methodology employed 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 appropriate methodology for the purposes of estimating the cost of capital for a notional BNE peaking plant in a specific region.

7.3.5 OTHER ISSUES

The RAs note that the CEPA/PB report supports the RA consultation paper included an annex on cost of capital inputs to the calculation in the consultation paper. CEPA/PB has consistently benchmarked all their analysis to market evidence sourced from Bloomberg and other public sources, which respondents could source to find this information. With regards to the point surrounding the risk-free rate, they use a real WACC rather than a nominal WACC in the BNE computation.

Overall the RAs find there is evidence received to merit a change the specific parameter assumptions of the Debt premium used in the building block cost of capital estimate. The Debt premium has increased from 1.75% to 2.00% which increases the Cost of debt. The UK pre-tax WACC increases from 6.26% to 6.41%, while the ROI WACC increases from 9.59% to 9.74%.

Based on this the SEMC have decided that the remaining WACC values detailed in the consultation paper will be used for the 2012 BNE calculations. These are summarised below.

Element	2012 RoI	2012 UK
Risk free rate	5.50%	1.75%
Debt premium	2.00%	2.00%
Cost of debt	**7.50%**	**3.75%**
ERP	4.75%	4.75%
Equity beta	1.25	1.25
Cost of equity	**11.45%**	**7.70%**
Taxation	12.50%	26.00%
Pre-tax cost of equity	13.09%	10.41%
Gearing	60.00%	60.00%
Pre-tax WACC	**9.74%**	**6.41%**

Table 7.3 – *Proposed WACC values to be used for the BNE Peaker for 2012*

8 BEST NEW ENTRANT PEAKER FOR 2012

8.1 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.

Cost Item	Republic of Ireland Dual Fuelled	Republic of Ireland Distillate	Northern Ireland Dual Fuelled	Northern Ireland Distillate
Investment Cost (excl Fuel Working Capital	119,876	116,084	115,661	113,788
Initial Working Capital (including Fuel)	6,863	6,499	6,864	7,077
Residual Value for Land & Fuel	-659	-765	-1,551	-1,777
Total Capital Costs	**126,080**	**121,818**	**120,975**	**119,088**
WACC	9.73%	9.73%	6.41%	6.41%
Plant Life (years)	20	20	20	20
Annualised Capex	14,542	14,050	10,903	10,733
Recurring Cost	12,582	6,134	8,360	4,794
Total Annual Cost	**27,124**	**20,184**	**19,263**	**15,527**
Capacity (MW)	193.9	192.5	193.9	192.5
Annualised Cost per kW	**139.89**	**104.85**	**99.34**	**80.66**

Table 8.1 – *Annualised costs for BNE Peaker for 2012*

8.2 DECISION ON BEST NEW ENTRANT PEAKER FOR 2012

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 2012 is the Alstom GT13E2, located in Northern Ireland and uses Distillate fuel

9 INFRA MARGINAL RENT

9.1 INFRA MARGINAL RENT FROM CONSULTATION PAPER

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 Validated SEM Plexos Forecast Model 2011-12 has been published by the RAs[7]. Twenty five full year half hourly simulations of the SEM in 2012 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.

9.2 RESPONSES TO INFRA MARGINAL RENT

Four responses were received in relation to the proposed revenue from Infra Marginal Rent.

- Viridian stated that it was inappropriate to deduct infra-marginal rents from the calculation of the capacity Pot and in doing so in their view is contrary to the objectives of the CPM.
- NEAI was also opposed to the concept of deducting IMR rent from the annual cost of a peaker. They stated that receipt of these payments is unpredictable and uncertain and will be discounted by any investor at the project appraisal stage.
- Synergen response stated that the paper SEM-11-025 assumes that the BNE Peaker runs in all periods where it would get IMR. They stated in principle this is over-optimistic; that the RAs should consider applying a probabilistic availability to it as a combination of scheduled and forced outages means that it would (in practice) not maximise its IMR in the assumed manner.
- Endesa Ireland believed it is crucial that if the new DC model resulted in an outcome other than zero infra-marginal rent, any modification to the capacity pot inputs should be consulted upon by the RAs.

9.3 DECISION ON INFRA MARGINAL RENT

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 2012.

The RAs continue to believe that the BNE plant would have the opportunity to earn IMR. As this is a revenue stream that is separate from the energy market (and capacity market), it is appropriate that this revenue stream should be removed from the BNE Peaker fixed costs.

Therefore for the purposes of the 2012 BNE Calculation, the SEMC have decided that there will be zero Infra Marginal Rent, as calculated from the latest validated SEM Plexos Forecast Model.

[7] http://www.allislandproject.org/en/market_decision_documents.aspx?article=151a9561-cef9-47f2-9f48-21f6c62cef34

10 ANCILLARY SERVICES

10.1 ANCILLARY SERVICES FROM CONSULTATION PAPER

The AS rates for tariff year 2011/12 have not be developed, they will be subject of a consultation during the summer of 2011. For the calculation of the Ancillary Services (AS) for the BNE peaker for 2012, the RAs have used the criteria as documented in the Harmonised Ancillary Services & Other System Charges - 2010/2011 rates consultation[8], developed with the SOs, detailing the proposed payments and charges. The TSOs' have published the approved rates and explanatory papers on their own websites along with the responses to the consultations on the proposed rates for the current tariff year, beginning 1 October 2011, for Ancillary Services and Other System Charges. Please refer to the following websites for details:

- http://www.eirgrid.com/operations/ancillaryservices/asothersystemcharges/
- http://www.soni.ltd.uk/chargingstatements.asp

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 for the consultation paper were:

- Unit size is 192.5MW
- Run hours is 2%
- Load factor is 60%

10.2 RESPONSES TO ANCILLARY SERVICES

A number of participants responded in relation to the AS calculation and these were divided into two categories:

- Whether it is appropriate for the methodology for calculating the BNE cost to include a subtraction of ancillary services income.

- The basis on which the ancillary services estimate was calculated.

A number of the respondents questioned whether it was appropriate to deduct ancillary services income from the calculation. An issue that has consistently been raised in previous Capacity Payment Mechanism consultations.

PPB stated that while the calculation of Replacement reserve (de-synchronised) is easily verifiable, the derivation of the remaining revenues is not set out in either the RAs consultation paper or the CEPA/PB paper and hence it is not possible to comment on the figures.

SSE thought it would be beneficial if the background calculations and assumptions in relation to this AS table could be made available to the market.

[8] http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=7ca6878c-058f-4497-8967-23a9c405d302

Synergen highlighted that the assessment of Ancillary Services revenue for the BNE Peaker is not jurisdiction specific but other significant elements of the assessment (e.g. gas transport / connection / WACC) are geographic. Indeed the TSO's recognise in the current consultation on harmonisation that AS requirements are jurisdictional and thus the likelihood of ancillary service rewards depends on the location of the BNE Peaker. On this basis, the RAs should re-visit the assessment of AS revenues.

Viridian argued a rational and prudent investor would not assume the ancillary service revenues deducted from the BNE price because there was no guarantee of being able to contract for all eligible services. They also went on to argue that there was no guarantee of ancillary service revenues that relied on being synchronized to the grid because these are exposed to the risk of transmission constraints and outages

Endesa put forward a substantial response on the AS calculation. Throughout the consultation period they were in discussions with the RAs to develop their understanding of how the RAs calculated the AS payment to the BNE. Their response was based around these discussions.

Key points highlighted from Endesa response include;

- All generators are required to comply with the Grid Code and must enter into an Ancillary Service Agreement (ASA) and if a generator does not provide the services as per the agreed values, they are penalised. The calculation of Ancillary Service payments to the BNE unit is not transparent and seems to neglect the requirement for an ASA.
- Endesa Ireland believes that the unit is not Grid Code compliant and requests clarification on these points and argues strongly that the BNE should meet all Grid Code requirements or the costs of the "Incentives" for ensuring Grid Code compliance should be included in the fixed costs.
- Endesa Ireland also argued that project/site specific elements should be included in the costs of the unit and also a higher penalty should be included in this calculation.
- Endesa also provided an assumed AS income based on ASA contract values equal to Grid Code requirements set out in Appendix A of their response and estimates that AS income would be €3.05 per kW, rather than €4.41 as assumed in the Consultation Paper – this results in an increase of €9,443,251 in the ACPS.

A couple of respondents also suggested the consultation paper did not provide sufficient evidence / transparency as regards the ancillary service revenue calculation.

10.3 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, as stated in the scope of the Medium Term review it was anticipated that the Annual Capacity Payment Sum (ACPS) for 2011 and 2012 will use the existing methodology for the calculations. The RAs continue to believe that the estimated AS revenue should be included in the BNE cost calculation.

In relation to using the indicative rates under consultation, like the TUOS charges the RAS will remain using the published 2010/2011 rates as the indicative rates are subject to change and would result in an unrealistic ACPS.

As regards the Grid Code compliance of the BNE unit, as stated in section 5.3, Alstom have confirmed that in the past they have developed an adapted/specific generator design for a grid code compliant power plant in Ireland.

PB considers that Irish Grid Code compliance, particularly in terms of leading power factor capability, is expected to be less onerous for smaller units, such as the GT13E2, than for those employed at the new Aghada CCGT plant in Ireland that utilises an Alstom gas turbine generator. In determining an increased generator cost the maximum impact thereof on the EPC price is estimated to be a 0.73% increase. As discussed in Section 3, a 0.73% uplift has been applied to the EPC price in the updated cost estimate analysis.

The estimates of ancillary services revenues contained in this decision document were based on information provided by the TSOs (Transmission System Operators), who have reviewed the Unit and proposed the following Ancillary Service values for use in the BNE calculation:

Parameter	Value	Unit	Source
POR	20.8	MW	SONI Minimum Function Spec for OCGTs
SOR	34.7	MW	SONI Minimum Function Spec for OCGTs
TOR1	34.7	MW	SONI Minimum Function Spec for OCGTs
TOR2	34.7	MW	SONI Minimum Function Spec for OCGTs
RR	192.5	MW	SONI Minimum Function Spec for OCGTs
Min MW for POR	19.3	MW	SONI Minimum Function Spec for OCGTs
Min MW for SOR	19.3	MW	SONI Minimum Function Spec for OCGTs
Min MW for TOR1	19.3	MW	SONI Minimum Function Spec for OCGTs
Min MW for TOR2	19.3	MW	SONI Minimum Function Spec for OCGTs
Min MW for RR	0.0	MW	SONI Minimum Function Spec for OCGTs
Reactive Power Leading	63.3	MVAr	SONI Minimum Function Spec for OCGTs
Reactive Power Lagging	144.4	MVAr	SONI Minimum Function Spec for OCGTs

Table 10.1 – *Ancillary Service values for use in the BNE calculation for 2012*

These values were chosen as the consultation paper recommended that the BNE be constructed in Northern Ireland and the values are outlined in the SONI Minimum Function Spec for OCGTs which can be found on SONI website[9]. Using these values in the attached model and the RA assumption of 60% load factor when running gives us the following output:

Parameter	Not Running [€/TP]	Running [€/TP]
POR		23.09
SOR		36.96
TOR1		30.54
TOR2		15.27
RR	49.09	7.7
Reactive Power Leading		8.23
Reactive Power Lagging		18.77
Total	**49.09**	**140.55**

Table 10.2 – *Summary of Ancillary Services for 2012*

The potential AS income using the RA assumption of 95% availability and 2% run hours = (49.09 * 0.93 * 48 * 365) + (140.55 * 0.02 * 48 * 365) = €849,101

The RAs also clarified the 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. A 192.5 MW direct trip and a 192.5 MW SND at zero notice time gives: Trip Charge = €10,087 & SND (current 10/11 rates): = €7,700

The Model has been provided as Appendix 1.

The SEMC have therefore decided that value of Ancillary Services that the BNE peaker for 2012 would achieve is **€831,314**. This equates to **€4.318** per kW for a 192.5MW unit.

[9] http://www.soni.ltd.uk/upload/Minimum%20Function%20Specification%20(OCGT)%20Rev1%200.pdf

11 DECISION ON BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2012

The table below shows a summary of the costs and the final annualised cost of the BNE Peaker for 2012. This includes the deduction of any revenues obtained from Infra Marginal Rent or Ancillary Services.

Cost Item	Northern Ireland Distillate
Annualised Cost per kW	80.66
Ancillary Services	4.32
Infra-marginal Rent	0.00
BNE Cost per kW	**76.34**

Table 11.1 – *Final costs for BNE Peaker for 2012*

12 CAPACITY REQUIREMENT FOR 2012

12.1 CAPACITY REQUIREMENT FOR 2012 FROM CONSULTATION PAPER

As detailed in the consultation paper, the methodology used for calculating the Capacity Requirement for 2012 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. This paper also contains the data sheets used in the Adcal calculation as a series of appendices.

12.2 RESPONSES TO THE CAPACITY REQUIREMENT FOR 2012

Nine respondents provided comments in relation to the Capacity Requirement Calculations. While some of these considered the Capacity requirement for 2012 as being reasonable, others welcomed the RA's intention to revisit the demand forecasts to ensure they reflect the actual demand trend.

AES commented on the RAs intention to retain a FOP of 4.23%, they stated that given that privatisation took place almost 20 years ago, along with the increased age profile of the generation fleet, the increased cycling of the older plants and a diminishing scale of improvement, AES considers that the FOP should be revisited in order to determine whether the principle and/or rate is still appropriate.

AES also supports the RA's inclusion of the cable fault on the Moyle Interconnector during 2010 in its Forced Outage Probability (FOP) calculation since this is consistent with basing the FOP on historical data and believes that the FOP for the Moyle Interconnector should be used for the East West Interconnector until its history is established.

Bord Gais Energy stated that the short-term reduction used in the BNE calculation does not match the paper's aim to incentivise capacity adequacy in the long term.

Bord na Moná noted the comments contained in last year's Decision paper in relation to 'the removal of capacity credits for wind' and the treatment of 'reserve margin' on the system. However, again this year the deemed capacity requirement reserve margin, (ratio of the deemed capacity requirement to peak demand) remains extremely tight at circa 7%. Citing, the BNE Decision paper (SEM-10-053) "the cold weather in January 2010 was more like a 1 in 40 year weather event". However, it would labour the point to refer back to the harsh conditions and the all time record demand which occurred in late December 2010. Surely now it 'would be prudent and responsible to calculate peak demand recognising that economic conditions are not necessarily the main driver".

Synergen was concerned that the capacity requirement is suppressed because the assumed peak demand excludes demand driven by recent extreme weather events as "outliers" whereas such high peak demands driven by recent extremely cold winters may not be "outliers" but rather the new "average winter" peak situation. They also stated that the TSOs recognise that forced outage probabilities are not independent during in cold weather events i.e. at times of peak. Thus the capacity requirement related assumption made regarding forced outage probabilities is unrealistically low and leads to suppression of LOLE at times of peak. The RAs should seek the views of the TSOs on the appropriate level of FOPs applicable at system peak in order to correctly determine the capacity requirement.

IWEA stated that the purpose of the Capacity Payment Mechanism was twofold; to remunerate the long-term financing requirement of investment in generation capacity and to incentivise availability of plant that has been built. They argued that reflecting a short-term reduction in demand is actually counter to the need to provide a secure supply of electricity to customers. Given that investment in generation is a long-term commitment with a long lead time for delivery, a reduction in the capacity pot based on a temporary, recession-driven drop in demand does not provide an efficient signal to exit the market because capacity that may be required again within a year or two as demand recovers, may be incentivised to exit the market

SSE also made comments regarding the short-term demand forecasts, and stated that it would seem more appropriate to remove this demand side variation from the methodology going forward, moving towards a fixed level reflective of a maximum longer-term level of demand.

Endesa Ireland requested that if there is to be a change in the demand forecast for the 2012 BNE that the RAs consult with stakeholders.

NEAI stated that it is vital for future investment that a realistic estimation of annual capacity requirement is made based on realistic assumptions of future developments in supply and demand. They believed that the proposed capacity requirement for 2012 understates the necessary volume on account of the inclusion of the Moyle and East/West interconnector with a lower Forced Outage Probability (FOP).

PPB also commented on the use of “target” forced outage rates and believe that actual rates (averaged over a number of years) should be used which more accurately reflects the risk to security of supply. They also highlighted their concerns by the experiences over the last two winters when during the cold spells, high pressure resulted in minimal generation by all the wind generators.

Viridian put forward a substantial response regarding the capacity requirement; it was their considered view that the calculated capacity requirement for 2012 was materially under-stated for a number of reasons, namely:

- It assumes that generator forced outages are completely independent events which is inaccurate given recent cold weather experience; For example SONI and EirGrid conclude on page 60 of the latest GAR: “We presume that the forced outage probability is the same at all times and not linked to the outages of other generators. In reality this is not entirely true, as extreme weather events make the simultaneous failure of generators more probable. This may lead to us overestimating system adequacy somewhat, especially since these failures are likely to coincide with periods of high demand”. Given recent documented experience over the last two winters we struggle to understand why the RAs still continue to use this assumption as a basis for their calculations.
- Extreme cold weather events are assumed to be discountable outliers in peak demand projections even though Ireland suffered two such events over the last two winters – a more prudent approach is required. We strongly suggest it would be prudent and responsible to calculate peak demand recognising that economic conditions are not necessarily the main driver and would note that all peak demand records (with the exception of the Summer night valley) have been set over the last two winters despite the economic downturn.
- Assumed plant availability is inappropriately projected from expected improvements – this should be based on historical data on an-island basis.

12.3 UPDATE ON DEMAND FORECASTS & IMPACT ON CAPACITY REQUIREMENT FOR 2012

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 discussions with SONI resulted in no change to the NI load forecast, but they did provide updated wind curtailment information. They also received some further updates from NIE with regards to small scale (Non-Market Non-Wind) generation for 2012 which resulted in a 0.2MW reduction in the Non-Market Non-Wind generation. SONI had received some further updates from NIE with regards to wind farm connection dates and provided an updated the “NI Wind Profiles” file for 2012. The revised NI connections dates resulted in a reduction in the weighted wind by about 19.5MW.

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

12.4 DECISION ON CAPACITY REQUIREMENT FOR 2012

Some respondents, as with last year, noted that it would be prudent and responsible to calculate peak demand recognising that economic conditions are not necessarily the main driver. In conjunction with the TSOs the demand forecast calculation takes into account economic conditions, historical yearly load shape and typical weather patterns.

Some of the issues raised by the respondents relate to the methodology used in calculating the CPM pot. These should therefore be dealt with through the CPM review process. As part of the review process, the RAs had anticipated that the Annual Capacity Payment Sum (ACPS) for 2011 and 2012 will use the existing methodology for the calculations and therefore would not be altering the methodology for this year’s calculation.

There are several comments relating to the peak forecast used in context of the previous two winters. It is common in Europe to report generation adequacy against typical demand and a more extreme demand event e.g. one in 3 or 5 year demand. Practice does vary from country to country. From discussion with the TSOs the RAs feel that the past two winters do not give sufficient data to imply a forward trend towards colder winters.

The past two winters have been amongst the coldest on record, and therefore can be treated as being atypical (see Met Eireann’s, the Met office and the BBC’s reports)

- http://www.met.ie/climate/monthly_summarys/winter10.pdf
- http://www.metoffice.gov.uk/climate/uk/interesting/dec2010/
- http://news.bbc.co.uk/weather/hi/about/newsid_9376000/9376372.stm

If this does continue over the next few winters, only then can this be treated as an emerging trend.

In terms of the peak demand forecast, SONI adjust this to a temperature standard known as Average Cold Spell (ACS) that adjusts the actual figure to a figure that can be compared year on year if the temperature each year were averagely the same. The idea being that each winter peak is adjusted to the 'effective mean temperature' from over the last 25 years. This analysis enables the ACS adjusted winter peaks to be compared on the same level as extreme weather conditions are therefore taken out of the equation. It is this ACS corrected figure that is used, therefore the forecasted peak demand does account for the weather and temperature.

In the latest All-Island Generation Capacity Statement 2011-2020, both SONI and EirGrid used ACS corrected peaks as a base to forecast ahead, and this is the same forecast that have been used for the CPM Calculation.

In relation to the respondent comments on the lower FOPs used for the interconnectors, Moyle has traditionally had a low outage probability and the figure used reflects its historical average (including one High-Impact Low-Probability event). EWIC has been given a slightly higher than FOP than Moyle (excluding the one High-Impact Low-Probability event) and also a week long scheduled outage to represent potential 'teething problems'. It should be noted that as EWIC is therefore only part of the generation profile for 15 weeks of the year, altering its FOP will have a relatively small impact on the capacity requirement.

Considering the use of "target" forced outage rates, the Decision Paper AIP/SEM/07/13 sets out the RAs decision to set a target for Forced Outage Probabilities (FOP) to incentivise an improvement in plant performance above the historical levels. This value was calculated based on the observed improvements in plant performance following privatisation of the Northern Ireland portfolio in the 1990's and was computed at 4.23%. The Decision Paper (AIP/SEM/07/13) makes it very clear that the computed value was to be used in calculations going forward. The RAs have carried this figure forward in its quantification of the 2012 Capacity Requirement. The RAs note that there are indications that availability has changed over the past year which suggests a movement in the FOP rates. The plant availability used is based on an historical average availability achieved in Northern Ireland over a 5 year period and seen as best practice target. The FOP is within the proposed scope of review of the CPM Medium Term review and the FOP value used in the Capacity Requirement calculation may be revisited within this review in terms of calculating historical data on an-island basis. The RAs believe that in line with previous years, the mechanism should at this time continue to maintain the value of **4.23%** for the FOP.

The methodology of calculating wind capacity credit takes this into account by using typical, real wind generation data from previous years. This method is similar to that used in the Generation Adequacy Report. The System Operators are of the view that it correctly calculates the capacity worth of wind generation.

Based on the changes to the Northern Ireland connection dates information from SONI (which resulted in a new NI wind profile, a new WCC and a new weighted market wind capacity), the RAs worked with the TSOs in rerunning the Adcal model. The second run of the Adcal model result in the Capacity Requirement decreasing by 24MW to 6,918MW.

The inputs used in the 2012 consultation calculations are summarised below. The associated data sets are attached as appendices to this paper.

Input	Description
Load Forecasts for ROI and NI for 2012	A combined load forecast for 2012, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. The period used for analysis was 1 January 2012 to 29th December 2012 as the AdCal model uses a 364 day sample. Two traces were agreed: 1) Total Load Forecast for 2012

	2) Total (In Market) Conventional Load Forecast See Appendix 2 – Load Forecast for 2012
Generation Capacity	A list of all generation to be in place in 2012 was determined, including the Sent Out Capacity for each unit. For any units to be commissioned or decommissioned during 2012, the Capacity available was adjusted accordingly to reflect the actual period they are available (time weighted average). Dublin and Meath Waste to Energy and Nore OCGT were not included in the model. Also Northwall 4 is unavailable. The Time-Weighted Capacity for Conventional Generation used in the Adcal model was **9537MW** See Appendix 3 – Generation Capacity for 2012
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 2012 used was **2,820**MW. This results in a Capacity Credit of **0.148**. The Time Weighted Market Wind Capacity in 2012 was **2,277**MW. Therefore the Wind Capacity Credit is derived as 336**MW** (2,267 x 0.148) See Appendix 4 – Wind Capacity in 2012 See Appendix 5 – Wind Capacity Credit (WCC) curve
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. See Appendix 6 – Average SOD for 2012
Force Outage Probability (FOP)	In line with previous years, the RAs maintained the value of **4.23%** for the FOP. It should be noted that an FOP of 1.431% was used for the Moyle Interconnector, based on historical data which includes the data for cable fault on Pole 1 from 09/09/2010 to 18/11/2010.
Generation Security Standard (GSS)	The RAs maintained the value of **8 hours** for the GSS.

Table 12.1 – *Summary of Inputs into Adcal Model*

The TSOs ran the AdCal model with the new NI wind profile, the new WCC and the new weighted market wind capacity. This resulted in a reduction, which was caused by a change in the perfect plant equivalent of the reference plant. This changed by 1 MW in the new calculation, from 120 MW to 119 MW[10]. This increased IPQ gives 'real plant' a slightly higher capacity credit therefore reduces the amount of 'real plant' calculated to meet security of supply.

As a result of the analysis carried out in conjunction with the TSOs, the RAs have determined that the Capacity Requirement for 2012 is **6,918MW.**

It is noted that this is a decrease of 0.06% from the Capacity Requirement from 2011.

The Capacity Requirement for 2012 is 6,918MW

[10] 1 MW is well within the margin of error for the AdCal model.

13 ANNUAL CAPACITY PAYMENT SUM FOR 2012

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement for 2012 as detailed in Sections 11 and 12 above, the Annual Capacity Payments Sum (ACPS) for 2021 is determined to be €528.1m. The proposed figures are detailed in table 13.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2012	76.34	6,918	528,120,120.00

Table 13.1 – ACPS for the Trading Year 2012

The Annual Capacity Payments Sum (ACPS) for 2012 is €528.1M