Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement For the Calendar Year 2011

Consultation Paper

28th May 2010

SEM-10-034

1 CONTENTS

2 INTRODUCTION

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

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

and

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

The methodology for the determination of the fixed costs of a BNE peaking plant was set out by the Northern Ireland Authority for Utility Regulation (NIAUR) and the Commission for Energy Regulation (CER), together the Regulatory Authorities (RAs), in two decision papers published on the All-Island Project website in 2007[1]. Subsequently, the Regulatory Authorities reviewed these costs in relation to the determination of the value of the Annual Capacity Payment Sum for the calendar year 2008[2]. The same process was used for the calculation of the fixed costs of a BNE peaking plant for 2009, 2010 and now 2011. The consultation paper and final decision paper for 2010 were published on the AIP website[3]. The Annual Capacity Payment Sums for 2007, 2008, 2009 and 2010 are summarised in Appendix 1 of this paper.

This Consultation Paper sets out:

1. The options for the BNE peaking plant for 2011 and proposes a technology option. The paper then explores the fixed costs associated with the proposed technology option as well as the financial parameters and sets out the proposed resultant value in €/kW/year.

2. The proposed Capacity Requirement for 2011 and the approach used for its determination.

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

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

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

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

[3] Fixed Cost of a BNE Peaking, Capacity Requirement, and ACPS for 2010:Decision Paper (SEM-09-087)

varied preferences and comments received to the consultation paper, the RAs have decided to amalgamate these issues into the comprehensive review of the CPM which is being undertaken this year. This area is discussed in further detail in Section 4 of this paper. For the avoidance of any doubt, it has been decided that the same methodology as applied in previous years will be used in the determination of the fixed costs of a BNE peaking plant for 2011.

The RAs have engaged Cambridge Economic Policy Associates (CEPA) in association with Parsons Brinckerhoff (PB) to assist in the calculation of the fixed costs of a BNE peaking plant for 2011.

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

The structure of this document is as follows:

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

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

Section 4 provides and update on the CPM Medium Term review.

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

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

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

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

Section 9 contains a proposal of the Best New Entrant Peaker for 2011;

Section 10 presents the Infra-marginal Rent for the chosen BNE technology;

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

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

Section 13 details the calculation of the Capacity Requirement for 2011;

Section 14 provides an indicative value for the Annual Capacity Payment Sum for 2011 based on the proposals in this document;

Section 15 invites comments and views;

Appendix 1 summarises the Annual Capacity Payment Sum for 2007, 2008, 2009 and 2010

Appendix 2 compares the costs for the 2010 BNE Peaker and the 2011 BNE Peaker;

Appendix 3 contains a copy of the CEPA report provided to the RAs for the 2011 Calculations.

3 BACKGROUND

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

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

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

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

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

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

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

4 UPDATE ON THE CPM MEDIUM TERM REVIEW

4.1 BACKGROUND

On 9th March 2009 the SEMC published a consultation paper titled ***Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology Consultation Paper*** (SEM-09-023)[6]. The purpose of the consultation paper was to propose options to address a key concern raised by industry participants regarding the stability of the capacity payment pot due to the annual determination of the Best New Entrant Fixed Cost (BNEFC) and the Annual Capacity Payment Sum (ACPS).

The consultation paper left open the implementation timeframe of the options consulted on but explicitly stated that, should the SEMC decide to adopt a more radical approach, then the practicalities of implementing such an option would be amalgamated within the medium term review of the CPM flagged for later 2009-2010. In the paper, the SEMC signaled its intention to carry out a further review of the CPM in the medium term. The main purpose of this review is to examine if the current design of the CPM can be further improved to better meet the CPM objectives.

4.2 CPM MEDIUM TERM REVIEW

The RAs have now completed three iterations of calculating the capacity pot. The RAs believe that the SEM is now well enough established and there is sufficient historical data and opinions collated from the various consultation processes to allow the RAs to carry out a review of the CPM.

On 8th April 2009 the SEM Committee (SEMC) published a consultation paper (SEM-09-035)[7], documenting the scope of work that the SEMC proposed to carry out in relation to a medium term review of the Capacity Payment Mechanism.

The RAs, on half of the SEMC, intend to review the current process used for distributing the capacity pot among generators and the calculations for payments by suppliers. The SEMC considers the CPM as a key feature of the SEM design. The SEMC believe that extensive analysis and consultation on this topic took place prior to SEM Go Live and that the concept of the CPM should remain in place. The SEMC wishes to satisfy that the correct signals and appropriate incentives or rewards are inherent in the design, so as to meet its objectives optimally. In particular the SEMC are mindful that CPM provides signals for new entry/investment and should reward plant and capacity in accordance with its performance.

The areas under consideration in this paper (SEM-09-035)[9] are detailed below:

- Assessment of CPM in SEM (historical analysis)
- Impact of CPM on Customers
- Incentives for Generators Capacity
- Payments when Capacity is needed

[6] http://www.allislandproject.org/GetAttachment.aspx?id=9f4bfc9b-5f60-4ca4-8a84-58158a5bb14f

[7]http://www.allislandproject.org/en/cp_current-consultations.aspx?article=4dde96cc-fdda-458b-9a3c-dc4a00692ac5

- Distribution of Capacity Payments
- Capacity Requirement Calculation
- WACC Methodology
- Infra Marginal Rent & CPM
- Impact of Exchange Rate in CPM
- Treatment of Wind in CPM
- Treatment of Interconnector in CPM
- Relationship of CPM with Ancillary Services
- Impact on Diversity of Generation & Security of Supply

On 18th November 2009, the RAs hosted a workshop on the methodology used to calculate the Capacity Requirement used in the determination of the Annual Capacity Payment Sum.[8]

In the CPM Medium Term Review Information Paper (SEM/09/105)[9], the RAs have included a time line detailing the expected durations of activities and the periods for further consultations on the topics under review within the CPM Medium Term Review. The RAs intend to carry out 2 consultations on the CPM Medium Term Review. The first consultation will be on aspects of the current CPM process. The second consultation will be on possible enhancements to the CPM. Further details on the work packages proposed and timelines for consultation can be found on the AIP website (http://www.allislandproject.org).

4.3 NEXT STEPS

The RAs have decided on the following approach on this subject.

1. The capacity pot for 2011 will be set following the same methodology applied in establishing its value in previous years.
2. Two consultation papers on the medium term review will be published later this year.

[8]http://www.allislandproject.org/en/cp_decision_documents.aspx?article=ba1ce3a7-23ff-4dd3-8a88-cd715106eeaa

[9] http://www.allislandproject.org/GetAttachment.aspx?id=3ce981eb-c853-4b03-a87f-1213e9b03daf

5 TECHNOLOGY OPTIONS

As stated earlier, the RAs have employed CEPA in association with PB to assist in the calculation of the fixed costs of a BNE peaking plant for 2011. Their independent report is detailed in Appendix 3 of this document and is referenced throughout this paper.

5.1 APPROACH USED FOR SELECTION OF TECHNOLOGY

In the interests of consistency the RAs required CEPA/PB to build on the approach used in previous years. The approach used by CEPA/PB is documented in Section 2 of their report.

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

- The BNE is a notional plant that would serve the last MW on the system.
- The plant is expected to operate no more than 5% of the time.
- The plant will enter the SEM in 2011.
- It should be noted that the period to build the plant is 18 months with a lead time for the transformer of 12 months.

In addition to conventional plant, consideration was also given to other options such as pumped storage, interconnector, Aggregated Generator Units (AGUs) and second-hand units.

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

5.2 CRITERIA FOR SELECTION

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

The long list of potential options contained 25 conventional plant types of different manufacturers, type and size. It also included Pumped Storage and Aggregated Generating Units.

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

- The technology option must be commercially available
- The technology option must have a proven track-record (typically defined as 3 examples of over 8000 running hours)
- The unit sizes must be between 30 and 200MW
- The technology option must ramp up to full load in less than 20 minutes
- The technology option must be able to fire liquid fuel
- The technology option must meet all environmental requirements (e.g Maximum NOx value for distillate firing = 120 Mg/Nm^3 and for gas firing = 50 Mg/Nm^3)

These details and the TSO input in relation to ideal ramp rate and size of plant are discussed in section 3.3 of CEPA's report.

5.3 SHORTLIST OF TECHNOLOGY OPTIONS

Using the criteria discussed in section 5.2 the number of options was reduced from 27 to 17. In order to further reduce the list of options to a manageable number to allow a detailed analysis, a comparison of equipment costs was carried out. The costs were based on the equipment costs published in the Gas Turbine World 2010 GTW Handbook. As a result of this analysis a recommended short list of options was proposed and a detailed analysis of these units was undertaken. The short listed units are:

- 1 x Alstom GT13E2
- 1 x Ansaldo AE94.2
- 3 x Rolls Royce Trent WLE
- 2 x General Electric LMS100

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

5.4 OTHER TECHNOLOGY OPTIONS CONSIDERED

Pumped storage was considered within the long list as the RAs have been in discussions with investors that are actively considering this sort of investment. This technology was deemed unsuitable due to the limited number of suitable sites and the total capital costs coming in between the central to high estimates.

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

The RAs propose that an AGU should not be used as the appropriate BNE peaker. While the technology appears to be well established and controllable under the desired requirements for a peaking plant, it was noted that the existing level of installed capacity is low, and it would be almost impossible to theoretically serve a sizable proportion of SEM demand with this technology. This is an important point because technologies which have a 'carrying capacity' could distort the signals sent by the CPM if used as the BNE peaker.

To illustrate by example, consider a situation where a peaking technology with very low fixed costs became available to investors, but could only be constructed up to a maximum of 50MW on the island. It would be possible then, at equilibrium, for the last MW of demand to be served by the *second* best peaking technology, one which could be built to an arbitrarily high capacity; in which case it would be more appropriate to set the Annual Capacity Payment Sum based on the annualised fixed costs of the second-best new entrant.

In terms of availability and appropriateness of using second-hand units for the BNE Peaker, PB investigated what hardware was currently available. Based on their investigation, they recommended that a second-hand unit would not be feasible for the 2011 BNE Peaker. This is discussed in the CEPA/PB report in Section 3.2.1.

5.5 ENGINEERING, PROCUREMENT & CONSTRUCTION (EPC) ANALYSIS

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

CEPA/PB carried out a detailed analysis of the four options short listed using the software package GT Pro in conjunction with its cost-estimating tool PEACE[10]. CEPA/PB took the values of EPC costs from the GT PRO tool, they then compared these with relevant actual costs they have experienced from projects that they have carried out in recent years. During last year's calculation, CEPA/PB applied a 3.8% uplift to PEACE cost estimates. Having undertaken the same exercise this year, PB do not propose to apply any multiplier to PEACE costs as they feel these figures are a more accurate reflection of market conditions. The RAs are satisfied with the approach taken by CEPA/PB in determining that there will be no adjustment factor used in 2011.

The EPC Cost estimates provided by CEPA/PB are detailed in Table 5.1 below.

Plant Type	Fuel Type	Average Lifetime Output (MW)	EPC Cost (€m)
1 x Alstom GT13E2	Distillate	190.1	91.0
	Gas	193.6	91.4
1 x AE94.2	Distillate	166.4	81.4
	Gas	167.7	81.9
3 x Trent WLE	Distillate	184.3	123.5
	Gas	185.6	121.5
2 x LMS 100	Distillate	195.1	134.2
	Gas	195.9	134.7

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

[10] GT PRO, GT MASTER and the associated PEACE programme are well established and respected GT thermal modelling and cost estimating software packages from Thermoflow Inc.

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

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

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

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

5.6 PROPOSED TECHNOLOGY OPTION

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

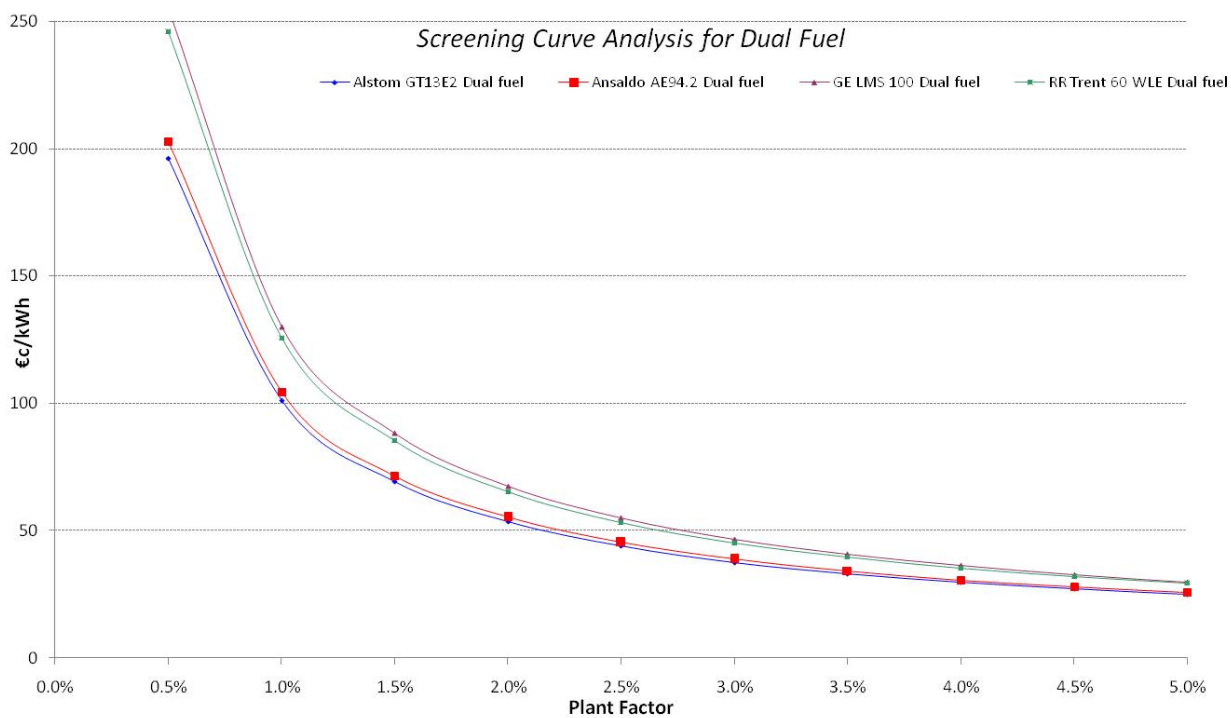

Figure 5.1 – *Screening Curve Analysis for Gas*

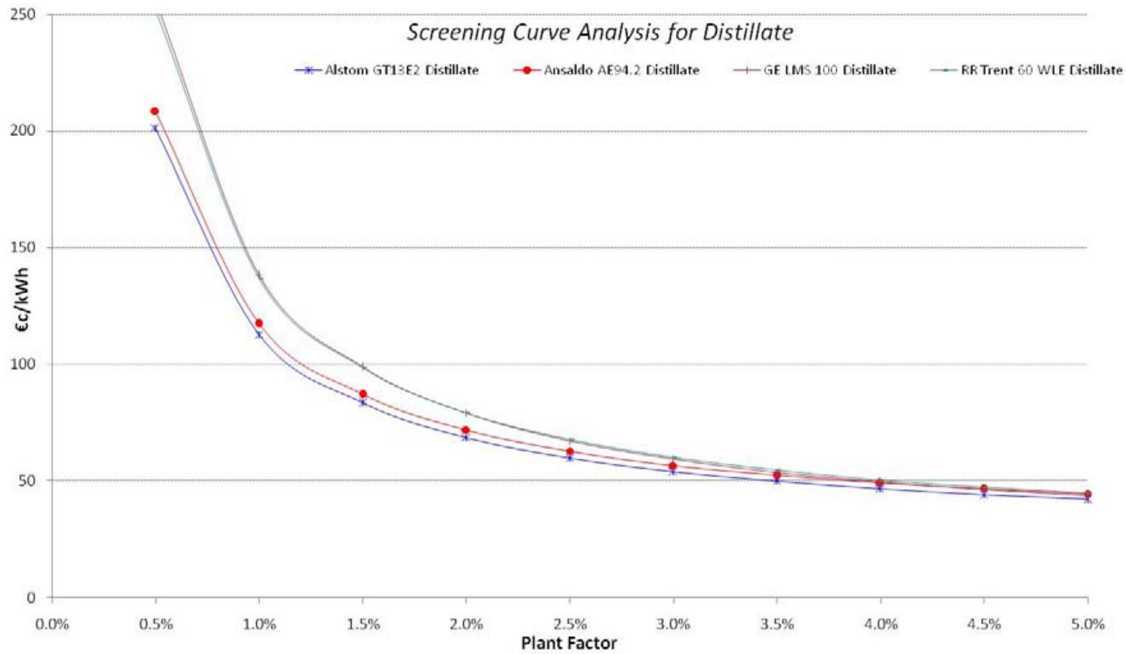

Figure 5.2 – *Screening Curve Analysis for Distillate*

Based on the screening curve analysis, the Alstom GT13E2 and Ansaldo AE94.2 are more favourable than the General Electric LMS100 and Rolls Royce Trent WLE options.

Based on the plant factor range of 0.0% to 5.0% used in the screening curve analysis, for every point in the range, the costs associated with the Alstom GT13E2 are lower that the Ansaldo AE94.2 costs.

Therefore, the recommendation for the technology to be used for the BNE Peaker 2011 is the Alstom GT13E2. It should be noted that the Alstom GT13E2 was the best option for both distillate and gas fuelling options in the screening curve analysis. This plant has a capacity of 190.1MW in distillate configuration and 193.6MW in duel fuel configuration.

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

The Proposed Technology Option for the BNE Peaker 2011 is the Alstom GT13E2

6 INVESTMENT COSTS

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

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

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

For the purposes of the BNE calculation the RAs viewed that the spot rate at time of developing document was appropriate, especially during a time of currency fluctuations and this rate will remain the same in the decision paper. This rate was a Euro to Sterling exchange rate of 1.1341.[11]

6.1 EPC COSTS

The EPC costs are covered in section 5.5 above. Table 6.1 summaries the proposed EPC costs for the Alstom GT13E2 for each fuel type. There is a difference in the EPC cost in the two locations due to the difference in costs associated with the differing transmission voltages. It should be noted that the costs below assume the period to build the plant is 18 months with a lead time for the transformer of 12 months being on the critical path.

Plant Type	Location	Fuel Type	Average Lifetime Output (MW)	EPC Cost (€m)
1 x Alstom GT13E2	NI	Distillate	190.1	€91,009,000
		Dual	193.6	€91,433,000
	RoI	Distillate	190.1	€92,199,000
		Dual	193.6	€92,629,000

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

6.2 SITE PROCUREMENT COSTS

The RAs in conjunction with CEPA/PB considered options for a suitable location in both Northern Ireland and the Republic of Ireland. The area of land needed is estimated to be 20,600m^2.

[11] The exchange rate used for the assessment is £1=€1.1341 (www.oanda.com 14 April 2010)

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

For the Republic of Ireland, there has been significant interests in power capacity despite the economic downturn, two new Combined Cycle Gas Turbines (CCGTs) are being developed at Aghada (432MW) by ESB PG and at Whitegate (445MW) by Bord Gáis, both these CCGTs are located in close proximity to each other in the south-west of Ireland. There is additional wind generation due for connection in the south-west over the next few years; as a result, it was considered that a BNE investor would be able to obtain agricultural land close to a relatively unconstrained part of the transmission network.

Due to the significant movements in the RoI economy over the last year, the value of land has reduced when compared with estimates used in the 2010 BNE Calculations. There is evidence that suggests that agricultural land value in the RoI have suffered a major reduction for the 3rd year in succession. For example the Knight Frank Ireland report indicated that the national average price paid for farmland in 2009 was 9,678 euro/acre, a drop of 43.3% since 2008. As well as indicators from the CB Richard Ellis report and the National Asset Management Agency (NAMA) the land value in the RoI has approximately decreased by 50% from last year's report.

CEPA/PB sourced indicative costs of land from an independent property market expert for both Northern Ireland and the Republic of Ireland and the RAs are satisfied that the estimate for 2011 is a reasonable reflection of the current costs. These costs are detailed in the table below. Further details are available in Section 4.3.2 of the CEPA/PB report.

Location	Required area (m^2)	Site Costs (€)
Northern Ireland	20,600	1,443,247
Republic of Ireland	20,600	763,556

Table 6.2 – *Summary of Site Procurement Costs*

6.3 ELECTRICAL CONNECTION COSTS

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

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

Location	Electrical Interconnection Cost (€)
Northern Ireland	7,492.999
Republic of Ireland	5,676,000

Table 6.3 – *Summary of Electrical Connection Costs*

6.4 GAS AND MAKE-UP WATER CONNECTION COSTS

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

Location	Cost of water connection (€)	Cost of gas connection (€)
Northern Ireland	0	1,690,000
Republic of Ireland	420,000	3,400,000

Table 6.4.1 – *Summary of Gas and Make up Water Connection Costs*

The assumptions used for Northern Ireland was that minimal water connection costs would be incurred due to the proximity of the water mains to the proposed site. For gas a 1km gas pipeline to Belfast West was assumed. The assumptions used for the Republic of Ireland were an installed 1km water pipeline, 4 inches in diameter and a 2km gas pipeline to the site.

In previous years, the RAs determined that the BNE peaking plant would run on distillate only. The decision was largely due to the costs associated with booking gas capacity and a perceived lack of liquidity in secondary gas capacity trading. There are a series of short and long-term products available in the RoI and interruptible products available in NI.

- In NI the tariff consists of a capacity and commodity charge that applies for use of transmission network system. For 2009/10 the capacity charge was £0.31517/kWh with a commodity charge of £0.0005352. The 2010/11 Tariff with effect from 1st October 2010 to 30th September 2011 will be £0.30951/kWh and the commodity charge will be £0.0005074.

- In RoI the capacity charge is levied in respect of the Peak Day consumption requirement of the exit point. The Commodity element is applied in respect of each kilowatt of gas that is supplied through the system. For 2009/10 the peak day charge for use of the onshore network was €0.432614/kWh with a commodity charge of €0.000194 and on the interconnector system it was a charge of €0.221618/kWh with a commodity charge of €0.000090. The 2010/11 Tariff will be published by CER in September 2010.

Further information on the Gas transmission charges and assumptions used can be found in the CEPA/PB report in section 4.4.2

The RAs are committed to working together to establish Common Arrangements for Gas for NI and RoI, whereby all stakeholders can buy, sell, transport, operate, develop and plan the natural gas market effectively on an all-island basis. However at the time of this writing the standing policy from the SEM Committee stands, in that the cost of gas transportation capacity remains best interpreted as fixed. In this context, the costs of gas transportation capacity are considered to be part of the fixed cost of a dual fuelled unit.

6.5 OWNER'S CONTINGENCY

As with 2010 CEPA/PB has recommended an owner's contingency value of 5.2% of the EPC costs. This is based on their past project experience. Therefore in the case of the Alstom GT13E2 the estimated Owners Contingency is detailed in table 6.5.

Location	Fuel Type	Owner's Contingency Cost (€m)
Northern Ireland	Distillate	4,732,468
	Dual	4,754.516
Republic of Ireland	Distillate	4,794,348
	Dual Fuel	4,816.708

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

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

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

	Total Cost for Distillate (€)	Total Cost for Duel Fuel (€)
Financing NI	1,820,180	1,828,660
Financing RoI	1,843,980	1,852,580
IDC NI	1,880,234	1,913,430
IDC RoI	2,135,956	2,205,420
Construction Insurance NI	819,081	822,897
Construction Insurance RoI	829,791	833,661

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

6.7 INITIAL FUEL WORKING CAPITAL

The RAs have carefully assessed the asset capital cost within the BNE Calculation. The Fuel Working Capital for the initial fill is another cost which has to comply with various regulatory policies. This is required for a gas plant to adhere with the secondary fuel obligation in the Republic of Ireland[12]. The fuel security code for Northern Ireland is currently under review therefore it is assumed that the above obligation would be applicable in either jurisdiction.

CEPA/PB has estimated an initial fuel storage fill cost of €3.6m for Distillate and €3.6m for dual fuel. This is based on a requirement to run for 72 hours full load and an oil price of US$87.57/ barrel[13].

[12] http://www.cer.ie/GetAttachment.aspx?id=7946b756-ce83-471a-b8fa-04d91610af88

[13] Oil price used was ICE Brent Crude as traded on 14 April 2010 (source Bloomberg)

	Total Cost for Distillate (€)	Total Cost for Dual Fuel (€)
Working Capital for Fuel (either jurisdiction)	3,614,384	3,101,760

Table 6.7 – *Summary of Fuel Working Capital*

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

6.8 OTHER NON-EPC COSTS

CEPA/PB grouped the remaining costs together to allow a logical comparison of the data they held on their project experiences. The cost areas included under 'Other Non-EPC Costs' include EIA, legal, owner's general and administration, owner's engineer, start-up utilities (The RAs are mindful of the number of starts that this type of peaker will incur over the year as the market develops), commissioning, O & M mobilisation, spare parts and working capital. Based on CEPA/PB's experience, the Other Non-EPC Costs equates to 9.0% of the EPC Costs.

As with the calculation in 2010 the data used in calculating the percentage allocation for Other Non-EPC Costs was presented to the RAs but due to confidentiality, the derivation of this percentage allocation cannot be included in this paper. The RAs are satisfied with the approach taken by CEPA/PB in determining the Other Non-EPC Costs.

Location	Fuel type	Other non-EPC costs (€)
Northern Ireland	Distillate	8,190,810
	Dual	8,228,970
Republic of Ireland	Distillate	8,297,910
	Dual Fuel	8,336,610

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

6.9 MARKET ACCESSION AND PARTICIPATION FEES

Similar to 2009, the required fees to enter the SEM were considered. Based on the current tariffs, these will cost €3,915 and although small are included for completeness. These charges are payable to the market operator, SEMO.

Type of charge	Charge Cost (€)
Accession Fee	1,115
Participation Fee	2,800

Table 6.9 – *Summary Other Non-EPC costs for Alstom* GT13E2

6.10 SUMMARY OF INVESTMENT COSTS

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

Cost Item	RoI Dual Fuelled	RoI Distillate	NI Dual Fuelled	NI Distillate
EPC Costs	92,629,000	92,199,000	91,433,000	91,009,000
Site Procurement	763,556	763,556	1,443,247	1,443,247
Electrical connection Costs	5,676,000	5,676,000	7,492,999	7,492,999
Gas connection	3,400,000	0	1,690,000	0
Water connection	420,000	420,000	0	0
Owners Contingency	4,816,708	4,794,348	4,754,516	4,732,468
Financing Costs	1,852,580	1,843,980	1,828,660	1,820,180
Interest During Construction	2,205,420	2,135,885	1,913,430	1,880,234
Construction Insurance	833,661	829,791	822,897	819,081
Initial Fuel working capital	3,101,760	3,614,384	3,101,760	3,614,384
Other non EPC Costs	8,336,610	8,297,910	8,228,970	8,190,810
Accession & Participation Fees	3,915	3,915	3,915	3,915
Total	**124,039,210**	**120,578,769**	**122,713,394**	**121,006,318**

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

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

7 RECURRING COSTS ESTIMATE

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

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

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

In relation to the Market Operator Charges, TuOS charges and Gas Transmission charges, the current published tariffs were used as sources. If updated tariffs relating to 2011 are available ahead of a decision on the cost of the BNE Peaker for 2011, the values in the table below will be adjusted accordingly to reflect these.

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
Transmission & Market operator charges	996,614	978,596	781,257	767,133
Gas Transmission Charges	1,607,162	0	876,388	0
Operation and maintenance costs	1,816,000	1,791,000	1,816,000	1,791,000
Insurance	1,482,064	1,475,184	1,462,928	1,456,144
Business Rates	1,515,929	1,488,523	926,686	606,622
Fuel working capital	187,222	218,164	197,768	230,453
Total	**7,604,991**	**5,951,467**	**6,061,027**	**4,851,352**

Table 7.1 – *Summary of Recurring Costs for BNE Peaker for 2011*

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

8 ECONOMIC & FINANCIAL PARAMETERS

8.1 INTRODUCTION

As with previous years, a key activity in the calculation of the BNE Peaker is the determination of WACC. CEPA/PB carried out an extensive investigation of the building blocks of WACC. Their analysis is detailed in Section 5 and Annex 3 of the CEPA/PB paper. As stated in 5.1 this is a project that will considered in the SEM in 2011. The format and approach CEPA/PB used in this section follows on from the format and approach that was used for the BNE calculation for the 2010 trading year.

8.2 NATURE OF THE BNE INVESTMENT

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

Area	Assumption
Type of Investor	It is assumed that the BNE investor is likely to be an integrated utility seeking to raise funding at the corporate level for the peaking plant investment project in the forthcoming year. In addition, it is assumed that the BNE is a green-field investment with no existing assets and associated financing costs.
Plant Life	The economic life of the project has been taken as 20 years.
Financing Structure	It is assumed that an efficiently financed peaking plant would broadly seek to match the maturity of its debt profile to the anticipated project life of 20 years. Therefore it is assumed that an average tenor of 10 years on the new debt. It is also assumed that the investor would seek to maximise the debt/equity ratio, but that in the current financial markets this would mean a gearing ratio of 60%. This is the same level of gearing as was used in the 2009 and 2010 calculations.
Credit Quality	It is assumed that a BNE investor has an investment grade credit rating in the range BBB to A. This is because a sub-investment grade entity would not be competitive for this type of project and indeed may struggle to raise the necessary funding.

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

8.3 WACC PROPOSALS

Annex 3 of the CEPA report provides a comprehensive summary of the assumptions used by CEPA/PB in their recommendation of the WACC to be used for the BNE Peaker for 2011. This calculation has been determined without prejudice to the value of the WACC calculated in other different regulatory workstreams. In summary, CEPA/PB recommended the appropriate range for the real pre-tax WACC for the BNE peaking plant is 4.95% - 7.1% in the Republic of Ireland and 5.6% - 7.1% in the UK.

A summary of the WACC parameters provided by CEPA is detailed in table 8.2 below. The 2010 WACC values have been included to allow a comparison.

	RoI			UK		
Element	**2010**	**2011 Low**	**2011 High**	**2010**	**2011 Low**	**2011 High**
Risk-free rate	1.88%	1.50%	2.50%	1.75%	1.50%	2.00%
Debt premium	3.50%	1.50%	2.50%	3.00%	1.50%	2.00%
Cost of debt	**5.38%**	**3.00%**	**5.00%**	**4.75%**	**3.00%**	**4.00%**
Risk-free rate	1.88%	1.50%	2.50%	1.75%	1.50%	2.00%
ERP	4.75%	4.50%	5.00%	4.75%	4.50%	5.00%
Equity beta	1.25	1.20	1.30	1.25	1.20	1.30
Post-tax cost of equity	**7.81%**	**6.90%**	**9.00%**	**7.69%**	**6.90%**	**8.50%**
Taxation	12.5%	12.5%	12.5%	28%	28%	28%
Pre-tax cost of equity	8.93%	7.89%	10.29%	10.68%	9.58%	11.81%
Gearing	60%	60%	60%	60%	60%	60%
Pre-tax WACC	**6.80%**	**4.95%**	**7.11%**	**7.13%**	**5.63%**	**7.12%**

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

The RAs used the recommended ranges in their determination of the suitable WACC values to be used for the BNE Peaker for 2011. The values to be used are the mid point of the ranges recommended by CEPA/PB. The proposed WACC values to be used for the BNE Peaker for 2011 are detailed in Table 8.3 below.

Element	2011 RoI	2011 UK
Risk-free rate	2.00%	1.75%
Debt premium	2.00%	1.75%
Cost of debt	**4.00%**	**3.50%**
ERP	4.75%	4.75%
Equity beta	1.25	1.25
Post-tax cost of equity	**7.95%**	**7.70%**
Taxation	12.50%	28.00%
Pre-tax cost of equity	9.09%	10.70%
Gearing	60%	60%
Pre-tax WACC	**6.04%**	**6.38%**

Table 8.3 – *Proposed WACC values to be used for the BNE Peaker for 2011*

9 PROPOSED BEST NEW ENTRANT PEAKER FOR 2011

9.1 SUMMARY OF COSTS

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

Cost Item	RoI Dual Fuelled	RoI Distillate	N Ireland Dual Fuelled	N Ireland Distillate
Investment Cost (excl Fuel Working Capital	120,937	116,964	119,612	117,392
Initial Working Capital (including Fuel)	5,565	5,799	5,309	5,613
Residual Value for Land & Fuel	-1,197	-1,356	-1,320	-1,469
Total Capital Costs	**125,305**	**121,407**	**123,600**	**121,536**
WACC	6.04%	6.04%	6.38%	6.38%
Plant Life (years)	20	20	20	20
Annualised Capex	10,957	10,616	11,107	10,922
Recurring Cost	7,605	5,951	6,061	4,851
Total Annual Cost	**18,562**	**16,567**	**17,168**	**15,773**
Capacity (MW)	193.6	190.1	193.6	190.1
Annualised Cost per kW	**95.88**	**87.15**	**88.68**	**82.97**

Table 9.1 – *Annualised costs for BNE Peaker for 2011*

9.2 RECOMMENDATION FOR BEST NEW ENTRANT PEAKER FOR 2011

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

The Proposed Best New Entrant Peaker for 2011 is the Alstom GT13E2, located in Northern Ireland and firing on Distillate fuel

10 INFRA MARGINAL RENT

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

The approach to the derivation of the estimated infra-marginal rent for the BNE peaker for 2011 replicates the process used in previous years (2007, 2008, 2009 and 2010). The approach used is to complete two plexos runs, one with the BNE peaking plant and all its true characteristics and one without. A unit commitment schedule is derived for the BNE peaking plant from the first plexos run and the actual infra marginal rent calculation is then derived using the original SMP estimations from the plexos run without the BNE peaking plant included.

To calculate the infra-marginal rent, the most up-to-date SEM Plexos model was procured from the Market Modelling Group, based in CER. 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 2011 were run, in which forced outage patterns were randomly generated[14] from one iteration to the next to give a spread of system margin scenarios across the year.

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

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

11 ANCILLARY SERVICES

The AS rates for tariff year 2010/11 have not be developed, they will be subject of a consultation during the summer of 2010. For the calculation of the Ancillary Services (AS) for the BNE peaker for 2011, the RAs have used the criteria as documented in the published consultation paper 'Harmonised Ancillary Services & Other System Charges Rates Consultation' published on 8th June 2009 (SEM-09-062)[15], developed with the SOs, detailing the proposed payments and charges to be applicable in the first year of implementation. As updated information becomes available the RAs will re-evaluate the AS calculation ahead of any final decision on the Capacity Requirement for 2011.

The RAs worked with the TSOs in calculating the appropriate costs for Ancillary Services under the propose criteria and formulae using the same methodology as was used in the 2010 calculation. The assumptions used in the Ancillary Service Calculations are:

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

The estimated value of Ancillary Services that the BNE peaker for 2011 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 2011*

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

12 INDICATIVE BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2011

The table below shows a summary of the costs and the final annualised cost of the BNE Peaker for 2011. This includes the deduction of any revenues obtained from Infra-marginal Rent or Ancillary Services.

Cost Item	N Ireland Distillate
Annualised Cost per kW	82.97
Ancillary Services	4.84
Infra-marginal Rent	0.00
BNE Cost per kW	**78.13**

Table 12.1 – *Final costs for BNE Peaker for 2011*

13 CAPACITY REQUIREMENT FOR 2011

13.1 INTRODUCTION

The methodology used for calculating the Capacity Requirement for 2011 is the same as that used in previous year's calculations. This section details the individual components and calculations that have been carried out for the quantification of the 2011 Capacity Requirement.

13.2 BACKGROUND TO CALCULATION OF CAPACITY REQUIREMENT PROCESS

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

A Decision Paper was published in February 2007 which set out the RAs decisions on the contents of the August 2006 Consultation Paper. This Decision Paper laid out the key methodology and individual data point assumptions. These parameters were used in calculating the 2007, 2008, 2009 and 2010 Capacity Requirement.

13.3 PARAMETER SETTINGS FOR CAPACITY REQUIREMENT FOR 2011

As anticipated in the initial consultation and decision papers, the same parameter settings have been used in the calculation for the 2011 Capacity Requirement. The following sections describe further each of these parameters.

13.3.1 GENERATION SECURITY STANDARD (GSS)

In AIP/SEM/111/06 the RAs stated that a single GSS for the entire island would be applied following detailed research by the TSOs in March 2007. This research was presented to the AIP Steering Group in May 2007 and the RAs subsequently decided on a GSS of 8 hours Loss of Load Expectation per annum. The GSS decided upon during the early part of 2007 following this research has been retained by RAs for the 2011 calculation.

13.3.2 DEMAND FORECAST

Considering the recent changes in demand as a result of the economic downturn, the RAs have worked closely with both TSOs in determining a suitable forecast for 2011. Recent demand trends and economic forecasts were used in the analysis.

As a result, the forecasted demand, used in the Capacity Requirement Calculation, as a percentage of the previous year for each jurisdiction was determined to be as follows:

	2010 Forecasted Total Energy Requirement	2011 Forecasted Total Energy Requirement
Republic of Ireland	-0.1%	2.2%
Northern Ireland	0.0%	0.5%

Table 13.1 – *Forecasted Demand of Total Energy Requirement*

EirGrid provided the following key points in relation to the above forecasts. Backup information can be found in the Eirgrid Generation Adequacy report 2010-2016 Chapter 3.

- For the purposes of calculating the Capacity Requirement, a TER reduction of -0.1% is forecasted for 2010. This is estimated with consideration of the observed export data described above and the most up to date economic forecasts. There is an increase of 2.2% in 2011 as it is assumed that the economy will begin to recover by 2011.

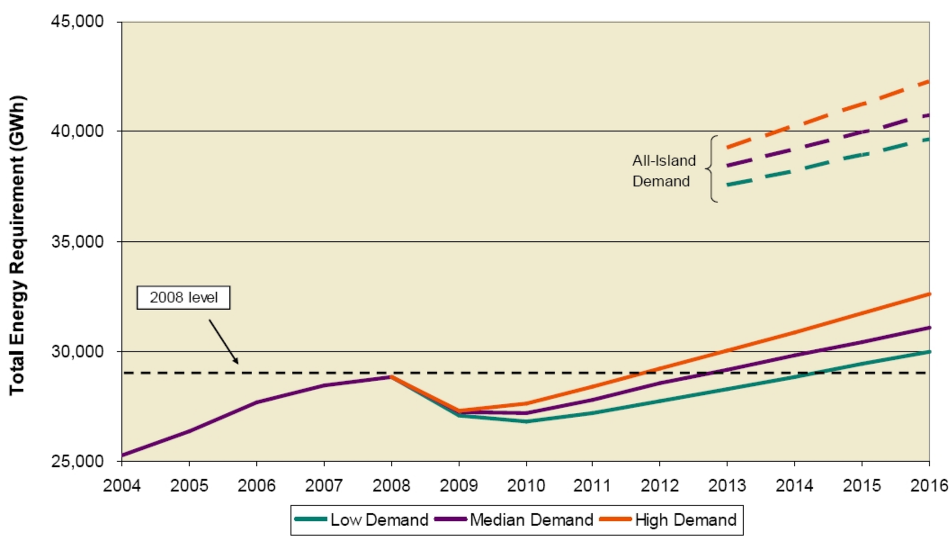

Figure 13.1 - *Demand Forecasts. All island values are included from 2013. Northern Ireland Forecasts were provided by SONI.*[16]

[16] Chart obtain from Eirgrid - Page 7 - Eirgrid Generation Adequacy Report 2010-2016 (http://www.eirgrid.com/media/Generation%20Adequacy%20Report%202010-2016.pdf)

- For the purposes of calculating the Capacity Requirement, the Eirgrid Median Demand forecast was used, as stated in Figure 13.1 a return to 2008 demand levels is not observed until 2013.

The RAs have investigated several economic commentary publications to determine a suitable forecast for 2010. Historically there has been a reasonable correlation between economic growth and increases in electricity demand. Previous demand forecasts have been made based on economic forecasts by economists such as the ESRI. In recent times though, the correlation between economic growth and electricity demand has changed as growth in the economy has transitioned to less energy intensive sectors. In April the ESRI (The Economic and Social Research Institute) issued its Spring 2010 Quarterly Economic Commentary.[17] Some of the main findings of their analysis include the following: for 2010, they expect GNP to be essentially unchanged from its 2009 volume; the corresponding figure for GDP is ½ per cent less than in 2009. For 2011, they expect GNP to grow by 2¾ per cent and GDP to grow by 2½ per cent. While this return to growth is to be welcomed, it should be seen as a modest pace of growth.

In the "First Trust Bank Economic Outlook & Business Review, March 2010[18]" it is forecast that the NI economy will remain weak until the middle of 2010. Economic recovery is likely to be consolidated in 2010H2. There are some signs that consumer confidence has steadied although fragility is still evident and the underlying trend is patchy. As of March 2010 GDP in NI is forecast by the First Trust Bank to rise by 0.5% in 2010 after falling by 2.5% in 2009. In the RoI it states that the economy is expected to recover slowly with GDP forecast to contract by another 2.5% Iin 2010.

The "Ulster Bank NI Quarterly Review[19]" published in December 2009 stated that 2009 is expected to show NI's steepest annual contraction in economic growth on record. The economy will return to growth in 2010 (+1.0%), but rates of expansion in the years ahead will be limited by inevitable cuts in public spending, as well as by factors including the performance of the RoI economy. The period ahead could be described as one of HURT, with Higher Unemployment and Rising Taxes. Northern Ireland will soon emerge from recession, but it will be years before the economy again achieves the output and employment levels experienced in 2007. Private sector output fell in Q2 2009 for the 8th consecutive quarter and has recorded a total decline of 9% to date. Manufacturing output is now back to 2003 levels.

These recent economic forecasts show that their predictions in these quarterly updates were more pessimistic that those in pervious issues. Ireland's economy has shifted considerably in the last few years, with the economy expected to recover slowly however, the economic backdrop will remain difficult over 2010, although the economy is expected to recover from 2011 onwards as the global economy swings upwards.

Considering the unprecedented times, the RAs are minded to revisit the forecasts above with the TSOs to ensure that they still reflect the actual demand trend. This activity will take place during the summer of 2010 ahead of any final decision on the Capacity Requirement for 2011.

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[17] http://www.esri.ie/irish_economy/quarterly_economic_commen/latest_quarterly_economic/

[18]http://www.firsttrustbank.co.uk/servlet/BlobServer?blobkey=id&blobwhere=1044897680707&blobcol=urlfile&blobtable=FTB_Download&blobheader=application/pdf&blobheadername1=Content-Disposition&blobheadervalue1=document.pdf

[19] http://www.ulsterbank.ie/content/group/economy/ni_indicators/downloads/Dec_2009.pdf

For the 2011 Capacity Requirement calculation, the TSOs were asked to provide half-hourly demand forecast profiles. Care was exercised to ensure that the jurisdictional traces were harmonised (i.e. based on the same reference year, 2008 (this is the same reference year that was used in the 2010 calculation), and day-shifted to align on a day-by-day basis). The RAs assisted in combining these jurisdictional load traces into a single, all-island demand trace for input to the CREEP calculation engine (described below).

13.3.3 GENERATION CAPACITY

Similar to the 2009 and 2010 Capacity Requirement calculations, the generation capacity data was already collected as part of the Directed Contracts process that took place in early 2010. As such this data was sourced from the Directed Contracts database, with discussion with TSOs as needed in supplement.

13.3.4 SCHEDULED OUTAGES

In the Decision Paper AIP/SEM/07/13 it was decided that scheduled outages for thermal plant would be quantified based on the previous 5 years of unit set data, and that the CREEP algorithm would be permitted to efficiently schedule these outages during the calendar year. This process has been applied in formulating the scheduled outage inputs for each unit in the 2011 Capacity Requirement process.

13.3.5 FORCED OUTAGE PROBABILITIES

The Decision Paper AIP/SEM/07/13 sets out the RAs decision to set a target for Forced Outage Probabilities (FOP) to incentivise an improvement in plant performance above the historical levels. This value was calculated based on the observed improvements in plant performance following privatisation of the Northern Ireland portfolio in the 1990's and was computed at 4.23%. The Decision Paper (AIP/SEM/07/13) makes it very clear that the computed value was to be used in calculations going forward. The RAs have carried this figure forward in its quantification of the 2011 Capacity Requirement. The RAs note that in general over the past year the system availability has improved which suggests an improvement in the FOP rates. As highlighted earlier, the FOP is within the proposed scope of review of the CPM Medium Term review and the current FOP value used in the Capacity Requirement calculation may be revisited.

13.3.6 TREATMENT OF WIND

The Decision Paper AIP/SEM/07/13 explains the RAs decision to treat wind as a netting trace against the load trace. This process has been repeated in the 2011 process. Individual wind output traces were provided by the TSOs. The wind traces were built upon the same reference year and aligned on a day-by-day basis with the load traces described earlier.

13.3.7 CREEP CALCULATION PROCESS

Having collected together the various input data points, the TSOs ran the iterative CREEP[20] software process to calculate the 2011 Capacity Requirement.

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

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

1. Use CREEP to calculate the Loss Of Load Expectation (LOLE) for 2011 that arises from the conventional market capacity, employed to meet the 2011 load trace with wind output netted from this trace.

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

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

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

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

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

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

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

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

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

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

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

[20] Note that for 2011, the TSOs used the 'CREEP' model.

13.4 PROPOSED CAPACITY REQUIREMENT FOR 2011

As a result of the analysis carried out in conjunction with the TSOs, the RAs have determined that the Capacity Requirement for 2011 is **6,902MW.**

It is noted that this is an increase of 1.11% from the Capacity Requirement for 2010.

The Proposed Capacity Requirement for 2011 is 6,902MW

14 INDICATIVE ANNUAL CAPACITY PAYMENT SUM FOR 2011

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement for 2011 as detailed in Sections 12 and 13 above, the Annual Capacity Payments Sum (ACPS) for 2011 is proposed to be €539.26. The proposed figures are detailed in table 14.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2011	78.13	6,902	539,262,877

Table 14.1 – ACPS for the Trading Year 2011

It is noted that this is a decrease of 2.15% from the ACPS for 2010.

The Proposed Annual Capacity Payments Sum (ACPS) for 2011 is €539.26M

15 VIEWS INVITED

Views are invited regarding any and all aspects of the proposals put forward in this Consultation Paper, and should be addressed (preferably via email) to both Jody O'Boyle at jody.o'boyle@niaur.gov.uk and Clive Bowers at cbowers@cer.ie by **5pm on 30/06/2010**.

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

16 APPENDIX 1 - ANNUAL CAPACITY PAYMENT SUM FOR 2007, 2008, 2009 & 2010

The annualised fixed cost of the BNE Peaker is multiplied by Capacity Requirement resulting in the Annual Capacity Payments Sum (ACPS). The ACPS for the Trading Years 2007, 2008, 2009 and 2010 are detailed in Table A1.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2007	64.73	6,960	450,517,348
2008	79.77	7,211	575,221,470
2009	87.12	7,356	640,854,720
2010	80.74	6,826	551,133,375

Table A1.1 – ACPS for the Trading Years 2007, 2008, 2009 and 2010

17 APPENDIX 2 – COMPARISON WITH 2010 BNE PEAKING PLANT

The table below shows a comparison of the costs for the 2010 and 2011 BNE Peaker Calculations.

Comparison of Costs for 2010 and 2011 BNE Peaker Calculations	2010 Decision	2011 Consultation	Variance	% Variance	Comment
<u>Site Procurement</u>	1,425,000	1,443,247	18,247	1.28%	An independent assessment was carried out on current land values, The site remains unchanged from last year and the RAs are satisfied that the estimate for 2011 is an reasonable reflection of the current costs
<u>Post Financial Close Costs</u> **EPC Total**	89,569,000	91,009,000	1,440,000	1.61%	Overall, the estimate for 2011 for EPC is 1.61% higher than the figures used for 2010. EPC costs are using latest version of GT Pro, which includes increase costs submitted from suppliers.
<u>Electrical Interconnection</u>	7,400,000	7,492,999	92,999	1.26%	The figures for 2011 show an increase and are as a result of discussions with the TSOs and are therefore deemed as accurate.
Owners Contingency	4,649,000	4,732,468	83,468	1.80%	There is an increase in the level of contingency recommended but this is reflective in the increase in the EPC cost
Financing Costs	1,788,000	1,820,180	32,180	1.80%	This cost has been calculated as a % of the EPC costs for 2010 resulting in a higher figure.

Comparison of Costs for 2010 and 2011 BNE Peaker Calculations	2010 Decision	2011 Consultation	Variance	% Variance	Comment
Interest During Construction	1,821,000	1,880,234	59,234	3.25%	This cost is largely in line with the costs estimated in 2010.
Construction Insurance	805,000	819,081	14,081	1.75%	Construction Insurance
Initial Fuel working capital	3,110,000	3,614,384	504,384	16.22%	Increase in Initial Fuel Working capital has been associated with the increase in the Oil Price - 2010 Decision paper was US$65/barrel and the for 2011 consultation paper it is US$85.57/barrel.
Accession & Participation Fees	5,000	3,915	-1,085	-21.70%	Accession & Participation Fees have decreased from previous years, the latest charge is taken from the SEMO Revenue and Tariffs for October 2009 – September 2010 Decision Paper
Other non EPC Costs	8,046,000	8,190,810	144,810	1.80%	Other non EPC Costs
TOTAL INVESTMENT COST	115,507	117,392	1,885	1.63%	The overall investment cost for 2011 is higher than the costs for 2010, mainly due to the slight increase in the EPC estimate
Land & Fuel Residual Value	-1,145	-1,469	-324	28.31%	An adjustment had been made in 2011 to account for the residual value of the Land and Fuel.
Initial Working Capital	5,810	5,613	-197	-3.39%	An estimate was made of the initial working capital required. This includes the initial fuel required.
TOTAL ADJUSTED INVESTMENT COST	**120,172**	**121,536**	**1,364**	**1.14%**	Overall the Capital costs for the BNE peaker has increased by 1.14%. This is mainly due to the slight increase in EPC costs increasing and the fact that some of the other costs are calculated as a % of the EPC Costs.

Comparison of Costs for 2010 and 2011 BNE Peaker Calculations	2010 Decision	2011 Consultation	Variance	% Variance	Comment
<u>Capital Cost</u>					
Capex	120,172	121,536	1,364	1.14%	
Plant life (Years)	20	20	0	0%	No Change
WACC (%)	7.13%	6.38%	-0.75%	-10.52%	This reduction on the WACC has been driven by the falling corporate debt premium. See Annex 2 in the CEPA report.
<u>Other Costs</u>					
Operations and Maintenance	1,782,000	1,791,000	9,000	0.51%	
Transmission and SEMO charges	801,000	767,133	-33,867	-4.23%	These costs are derived directly from the published tariffs for 2009/2010.
Insurance and Miscellaneous cost	1,430,000	1,456,144	26,144	1.83%	This cost has been calculated as a % of the EPC costs for 2011 resulting in a higher figure.
Rates cost	576,000	606,622	30,622	5.32%	The same assumptions from 2010 were used in 2011 for calculating rates.
Fuel Working Capital	222,000	230,453	8,453	3.81%	
Total Costs	4,811,000	4,851,352	40,352	0.84%	**The overall estimate for these costs for 2011 is slightly higher than 2010**

Comparison of Costs for 2010 and 2011 BNE Peaker Calculations	2010 Decision	2011 Consultation	Variance	% Variance	Comment
Annualised Capital plus Fixed Costs (€/kW)	85.58	82.97	-2.61	-3.05%	
Energy Market Infra Marginal Rent	0	0	0	0%	
Ancillary Service Revenue	4.84	4.84	0	0%	The AS Costs has remained the same from the Decision in 2010 it will be reviewed with the AS rates for tariff year 2010/11 in the summer consultation
Capacity Requirement	6826	6902	76	1.11%	
Final BNE Cost	**80.740**	**78.13**	**-2.61**	**-3.23%**	**The Final BNE Cost for 2011 is lower, mainly due to the fall in the WACC %**

Table A2.1 – Comparison of Costs for the 2010 and 2011 BNE Peaker

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