Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant,

Capacity Requirement, and

Annual Capacity Payment Sum for Calendar Year 2009.

Decision Paper

11 September 2008

SEM-08-109

I. INDEX

II. INTRODUCTION

On 4 July 2008 the SEM Committee (SEMC) published a Consultation Document entitled 'Fixed Cost of a Best New Entrant Peaking Plant for the Calendar Year 2009' (AIP/SEM/08/083). This document sets out the decisions that the SEMC have made having considered the industry responses to that Consultation. The document includes full calculation of the final BNE Fixed Cost, the final Capacity Requirement and the final Annual Capacity Payment Sum (ACPS) for the calendar year 2009.

Detailed responses are provided by the SEMC to the individual comments provided by respondents in Appendix 1.

III. SUMMARY OF DECISIONS

The Best New Entrant (BNE) Peaking Plant for 2009 is a Siemens SGT5 2000E firing on distillate fuel, sited in the Republic of Ireland and connected to the grid via a double-circuit connection at 220kV.

The estimated annualised fixed cost, net of estimated infra-marginal energy rent and ancillary service revenue, is **€87.12/kW/year**.

The Capacity Requirement for 2009 is **7,356 MW**.

The product of these price and quantity elements yields an Annual Capacity Payment Sum (ACPS) for the 2009 Trading Year of **€640,854,720**.

Compared to the Consultation Paper, the following items have been reviewed and changed in calculating the final annualised fixed cost of the BNE Peaker:

- Site size has been changed from 4,800 square metres to 20,000 square metres resulting in a site cost increase from €1,343 million to €3,221 million in the Republic of Ireland (RoI) and from €2,244 million to €6,977 million in Northern Ireland (NI)

- Connection arrangements have been changed and the costs have increased from €2.550 million in both jurisdictions to €5.300 million in RoI and €3.550 million in NI

- Ancillary Services revenue in RoI has changed from €7.04/kW/yr to €6.69/kW/yr

- Gearing has changed from 70% debt in both jurisdictions to 60% debt in both jurisdictions

- The Nominal Risk-Free Rate has been updated and averaged over 30 recent days, from 4.58% to 4.56% in RoI and from 4.82% to 4.97% NI

- Interest during construction (IDC) has been revised to account for a change to the time allowed for construction from 12 months at a cost of €2.328 million to 15 months at a cost of €2.934 million

- Wet NO_x reduction equipment has been added at a cost of €2.2 million

The final 2009 ACPS of €640,854,720 compares to the 2007 and 2008 ACPS values of €450,517,348 and €575,221,470 respectively.

The SEMC has estimated the costs of a BNE Peaker from the perspective of a conservative investor. The details of individual elements are described in the sections below. Arguments can be made that the actual cost of particular items may turn out to be greater or less than the estimates presented here. However, the SEMC is of the opinion that the market adjustment it has applied (see section VII . 2), a relatively high equity risk premium and its decision, for the purposes of this exercise, to disregard the residual value of the plant at the end of its accounting life, mean that the final values reflect a conservative approach from an investor's perspective in estimating the total project cost.

The SEMC received several responses to the Consultation Paper that related to policy issues outside the scope of the quantification of the Best New Entrant Peaker cost calculation for 2009. The SEMC intends to consult fully and more directly with industry on the CPM price and quantity-setting methodology in due course. These comments will be considered at that stage.

IV. RESPONSES TO THE CONSULTATION

The SEMC received submissions from a number of participants and interested parties. Most respondents agreed that the content of these submissions could be made public, and the SEMC have published or intend to publish them.

Responses were received from:

- Viridian Power and Energy (VP&E)
- ESB International (ESBI)
- Irish Business and Employers Confederation (IBEC)
- Bord na Móna (BnM)
- Bord Gáis Energy Supply (BGES)
- ESB PG
- Bord Gáis Networks (BGN)
- NIE Power Procurement Business (PPB)
- Premier Power Limited (PPL)
- AES
- NIE Energy Supply (NIEES)

V. TECHNOLOGY CHOICE

The 4 July Consultation Paper proposed that the BNE would be a 168MW Siemens SGT5 2000E unit firing on distillate. Most respondents provided views on the proposed technology choice.

1. Plant Type, Dynamics and Size

Regarding the proposed choice of a heavy-duty (HD) open-cycle gas turbine (OCGT), responses were mixed but generally disagreed with the proposed selection of a heavy duty machine or criticised the elimination method by which the selection was made, or both.

VP&E were supportive of the choice of an OCGT and agreed that the Siemens technology had a proven track record.

ESBI and ESB PG did not agree that a heavy duty machine was appropriate. Both submissions argued that an aero-derivative should have been selected. ESBI argued that this was necessitated by the need for quick response times and high flexibility of peaking generation given the impact of increasing wind on the island. ESB PG raised similar arguments, also disputing the claim that the Siemens unit could achieve a 20 minute start-up time without additional investment. ESB PG also focussed on the improved value to system security that was obtained through having multiple small units, compared to fewer large units in the provision of peaking capacity.

AES expressed a view that a 20 minute start-up time might not be acceptable given the prevailing conditions on the island and increasing penetration of wind.

BGES, BnM and PPB did not directly challenge the specific technology selection, but criticised the method of progressive elimination by which the proposed choice was made.

PPL queried as to why only the multiple DLE configuration was considered when assessing multiple aero technology types.

Several respondents queried the apparent absence in the choice of criteria of the Integrated Pollution Prevention Control (IPPC) directive on Best Available Techniques (BAT) as defined by EC Directive 96/61 as had been included in the selection of a BNE Peaker in the 2007 decision process.

One respondent questioned the efficiency values quoted in the Consultation Paper, suggesting that these referred to efficiencies obtained when the units were firing on gas rather than distillate, noting that distillate firing tends to reduce the efficiency of OCGT plants compared to gas-firing. The respondent further noted that firing the unit on distillate would reduce the exportable capacity of the unit below that suggested in the Consultation Paper.

Consideration of Responses

The SEMC were provided with a range of possible choices and needed to consider each on merit against a set of pre-defined criteria to identify the best. The definition of 'best' is in this case subjective, because each candidate can offer strengths and weaknesses in different areas. The SEMC must consider the views of a rational investor in making a selection, taking into account the requirements of the System Operators (SO's). The elimination process used to choose the Siemens unit was based on a holistic analysis of cost components for each candidate. However, the final selection was necessarily based on a balanced judgement by the SEMC.

It should be emphasised that, in the shortlist provided in the Consultation Paper, all of the plant would generally represent plausible and defendable investments.

The SEMC accepts the argument that aero-derivative plant can generally offer better flexibility than heavy-duty OCGTs, including faster start-up times. This point was discussed with the System Operators (SO's), who did not feel that a heavy duty plant was inadequate in this regard.

On the question of why only one dual unit was considered, the Consultation Paper made it clear that none of the possible technologies were ruled out on size alone, and rather, that the possibility of double units for the aero-engine derivatives was considered. In the end only the Rolls Royce 60DLE was presented in the Consultation Paper as a potential 'double unit' as it fared best when looking at the screening curve analysis, even at low utilisation.

In relation to the comment made by ESB PG, the SEMC is satisfied that the costs as stated in the Consultation Paper relate to an OCGT plant capable of achieving full output in 20 minutes. In coming to this view it has taken advice from its engineering consultants.

The SEMC recognises that there is some difference in the application of the BAT criteria, as well as the introduction of a new criterion in this year's assessment relative to last year's. Less stress has been placed on the heat efficiency of the unit, while more has been put on the per-MW cost. The SEMC took the view that on balance, investors would prefer a lower per-MW cost to higher efficiency, as the efficiency does not heavily dictate the revenues the unit will receive in the SEM. Nonetheless, the need to comply with appropriate standards in plant efficiency remains essential.

To elaborate on the method of progressive elimination used, the table below shows the options remaining having considered unit size, start-up / dynamics and track record. The 2 x Rolls Royce Trent 60 DLE (considered to overcome the size issue) still faces a much higher per-MW cost than the other units and is therefore ruled out on this basis.

TABLE 1
SELECTION OF CONTENDERS FOR THE BNE PEAKING PLANT 2009

Unit Name	Capacity	Efficiency	Base Case Fixed Cost per yr[1]
2 x Rolls Royce Trent 60DLE	2 x 52 MW	42.0%	94.47
Alstom GT11 N2	114 MW	33.3%	83.71
GE 9E	126 MW	33.8%	81.45
Mitsubishi M701DA	144 MW	34.8%	81.91
Siemens SGT5 2000E	168 MW	34.7%	79.24
Alstom 13E2	180 MW	34.0%	81.23

The reason for rejecting the Alstom 13E2 also relates to cost, but in this case rather than just the total cost being much higher than the others (as was the case for the Rolls Royce), the Alstom's relative cost per unit of installed capacity makes it more expensive than some of the other units. It would be expected that as the size of a unit increases, economies of scale would lead to improvements in the per-unit cost. However although the Alstom 13E2 is much larger than the other units – 54MW larger than the GE 9E and 66MW larger than the Alstom GT11 N2 for example – its unit cost is not significantly cheaper in per-MW terms as might be expected with economies of scale. It is only fractionally cheaper than the GE 9E and is more expensive than the Siemens SGT5 2000E. The Mitsubishi M701DA has a higher cost per installed MW of capacity, despite a greater unit size than the GE 9E. For this reason both the Mitsubishi and the Alstom 13 E2 were ruled out by the SEMC.

It is worth noting that the final selection criterion considered the Best Available Techniques from the IPPC Directive – had the Alstom 13E2 not already been ruled out for the reasons set out above, the Siemens SGT5 2000E's higher efficiency is, at 34.7%, superior to the Alstom 13E2's of 34.0%.

Regarding the efficiency values quoted in the Consultation Paper, the SEMC has confirmed that these are nameplate manufacturer efficiencies typically quoted on the assumption of gas-firing. This means that initially, the efficiency obtained from the units would be slightly lower than as quoted in the above table, as the proposed BNE plant is firing on distillate rather than gas. However, the SEMC has decided to include water injection equipment (see sub-section 3 below) which will tend to increase the exportable capacity of the unit. The SEMC is of the view that the conservative estimates that have been made regarding the reduction in gross output (from 168MW) due to the various stages of the combustion cycle, combined with the introduction of the water injection equipment, will tend to offset the effect that firing on distillate will have on the exportable capacity. The SEMC thus believes that a value of 158.59MW exportable capacity for the proposed distillate-fired Siemens unit is reasonable.

The SEMC remains of the view that the Siemens does provide strong peaking flexibility, notwithstanding the merits of the other plant considered. Having confirmed with its engineering consultants the technical capability of the proposed plant as queried by AES, the SEMC has decided to retain the proposed technology.

[1] The values shown relate to the Republic of Ireland only for ease of illustration but similar relative differences exist for Northern Ireland too.

2. Fuel Choice

Several responses were received regarding the proposed choice of distillate fuel.

BGES did not agree that the plant should be distillate-fired, arguing that gas capacity booking is not problematic and that short-term gas products are available and that the plant should be gas-fired.

BGN also argued the plant should be gas-fired, highlighting the present lack of congestion in NI and the recent use of within-day products by some shippers. BGN also provided a graphical representation of secondary trading behaviour in recent months to back up their argument.

PPB agreed that gas-firing should be discounted as the tradability of gas transmission capacity in RoI does not facilitate avoidance of fixed capacity costs. No direct mention was made of the situation in NI.

Consideration of Responses

The SEMC welcome the recent improvements in secondary gas tradability on the island. Nonetheless, the SEMC is not convinced that the trading behaviour depicted in BGN's submission necessarily constitutes a liquid secondary market suitable for the needs of a peaking unit operating on gas which is expected to have low (and uncertain) running hours. The SEMC recognises this market is likely to develop in terms of volume, liquidity and number of participants in the future. Such developments would be expected to have an effect on the attractiveness of using gas as the primary fuel for a peaking unit.

On balance the SEMC has decided to retain distillate as the fuel type.

3. Emissions Abatement

The 4 July Consultation Paper proposed that it was unnecessary for a new entrant to install emissions reduction equipment because:

- A peaker would not be expected to run for more than 500 hours per year – the point at which the Large Combustion Plant Directive limit of 120 mg/m_0^3 applies.

- The proposed BNE would be compliant with Best Available Techniques requirements (including ground level concentrations) for the purposes of IPPC licensing.

Several participants disagreed with the SEMC's proposal.

VP&E commented that that ground-level concentration compliance with the appropriate environmental standards would be difficult without the reduction equipment, and drew attention to the fact that peakers on the island have historically operated for more than 500 hours per year.

ESB PG provided a detailed criticism of the emissions assumptions, claiming that the estimated emissions of the plant were too low. PG also argued that a rational investor would not limit themselves to 500 running hours per year.

PPB argued that the decision not to include the NO_x reduction equipment was not based on rigorous analysis and that it may not align with BAT principles.

<u>Consideration of Responses</u>

The Environmental Protection Agency (EPA) in RoI was contacted directly by the SEMC. The EPA confirmed that the key documents referred to in the Consultation Paper (and here) were relevant in considering the appropriateness of omitting wet NOx reduction equipment. The EPA confirmed that the document "*Draft BAT Guidance Note of Best Available Techniques for the Energy Sector (Large Combustion Plant Sector)*" should be used as a reference document for the purposes of identifying appropriate limits to be applied in RoI. Section 6 of that document identifies limits which it states are derived from "*the lowest emissions associated with BAT in the LCP BREF up to the basic requirements in the Large Combustion Plant Directive*", and states that for a gas turbine operating on liquid fuel the limit is identified as 120mg/Nm^3.

According to guidance on the Large Combustion Plant Directive (LCPD) published by the UK Government's Department for Environment, Food and Rural Affairs (DEFRA), gas turbines which are "*for emergency use that operate for less than 500 hours per year*" are excluded from the limits identified in the LCPD. The EPA confirmed that this derogation exists but noted that this would require the plant operator to commit to operate for less than 500 hours per year.

The SEMC's engineering consultants reviewed the associated costs of NO_x water injection equipment against other projects and experience they have acquired in operating on projects in Europe and internationally. Given the expected low running hours of the BNE peaking plant, it might be more cost effective to store sufficient demineralised water on site to meet the minimum running requirements and top up the water storage tanks with tanker deliveries of demineralised water, rather than incur the cost of a water treatment plant for the site. The tank requirements would be simpler than those for the storage of distillate, requiring a coned roof rather than the floating roof required for distillate. On this basis the SEMC estimates the cost of the water tanks for the BNE to be around €800,000.

Accounting for this and the cost of additional elements of the balance of plant, civil works and other tankage and vessels, the SEMC estimates the fixed costs of the water injection system for the BNE to be €2.2 million.

It is the considered view of the SEMC, having weighed the relative cost of water injection against the downsides of having limited running hours and the possibility of additional overhead in future years in the form of retro-fitting projects, that a rational investor would prefer to install the equipment at the time of construction for the cost estimated above.

The €2.2 million water injection cost has been added to the capital cost estimate.

4. Forced Outage Rate

There was one comment on the Forced Outage Rate, from AES, who highlighted that plant stress resulting from operation would cause higher outage rates than those assumed in the proposed decision.

Consideration of Responses

The SEMC is aware of this phenomenon of plant behaviour, but does not believe the 2% forced outage rate assumption is unrealistic given the expected operating regime of the plant.

5. Other Parameters

There are some additional plant parameters, including

- Efficiency Degradation (average 3% over 15 years)
- Planned Outage Duration (13 days per year)

which were not directly commented on by the respondents. These parameters have subsequently been retained as per the Consultation Paper.

VI. WACC

In the Consultation Paper the SEMC derived proposed parameters for input to a WACC calculation using the CAPM formulation method.

The SEMC considered whether models other than CAPM – such as arbitrage pricing theory and Fama-French models – might give more accurate insights into the returns required by equity investors. It found that, in common with other regulators, although CAPM has its limitations, it is the most robust way for a regulator to measure the returns required by shareholders.

The SEMC received many responses regarding the WACC parameters as outlined below:

1. Gearing

The Consultation Paper proposed using 70% gearing for financing the BNE Peaker as employed last year.

VP&E stated that obtaining 50% gearing for new projects was difficult, even in the presence of the explicit SEM CPM and that 70% was too high an estimate.

BGES did not agree that 70% gearing was appropriate, and argued that 50% would be more appropriate as was used in 2005 decision by CER for ESB Networks.

PPL argued that 70% was not achievable for a merchant independent peaking plant and that a more realistic gearing would be 25%, referring to regulated assets in the US which are geared at 50%.

AES argued for a lower gearing than 70%.

<u>Consideration of Responses</u>

Some of the respondents called attention to the recent volatility in the international credit market as part of their response. The SEMC has revisited this parameter in this context.

While the SEMC considers that 70% gearing is achievable, it is important to recognise that in the current financial climate it is likely that financial markets would be more receptive to projects with lower gearing. As such, the SEMC has decided to reduce the gearing from 70% debt to 60% in both jurisdictions. The degree of reduction in gearing advocated by PPL and BGES appear excessive to the SEMC.

Gearing Consultation Values – 70% (Ireland) / 70% (UK)

Gearing Decision Values – 60% (Ireland) / 60% (UK)

2. Nominal Risk Free Rate

The Consultation Paper stated a then-current Nominal Risk-Free Rate (NRFR) of 4.58% in RoI and 4.82% in the UK.

The following responses were received regarding the NRFR :

Bord na Móna argued that the daily variance of the NRFR is significant relative to the long term.

AES argued that financing decision should be based on LIBOR or similar products as these represented the rates to which investors are actually exposed.

Consideration of Responses

In reviewing the value of Nominal Risk Free Rate to be used the SEMC has considered the views expressed by Bord na Móna and others. The SEMC's consultants, upon review, have also advised that the spot rate used as the basis for the Consultation Paper has exhibited considerable daily volatility and therefore any spot value is unlikely to provide a reasonably representative longer term rate.

The consultants have suggested averaging the spot values over a monthly period to identify a more reasonable rate to be used for the BNE calculations. An average over a longer period could be employed but the SEMC considers a month to be reasonable. Accordingly the value of the Nominal Risk Free Rate has been re-determined by taking the average over the period from July 11 to August 12 and equates to 4.9748% in NI and 4.5608% in RoI.

The SEMC does not consider it appropriate to use an interbank rate as this contains elements which reflect the debt risk premium.

NRFR Consultation Values – 4.58% (Ireland) / 4.82% (UK)

NRFR Decision Values – 4.56% (Ireland) / 4.97% (UK)

3. Inflation

The following responses were received regarding the assumed rate of inflation:

BGES asked for the source of the estimate to be disclosed, arguing that the CER paper on Gas Transmission Allowed Revenues used a higher value than that quoted in the Consultation Paper.

Consideration of Responses

The European Central Bank (ECB) documentation used to compile the 2.4% inflation estimate mentions inflation expectations that 'have a risk on the upside', inferring the intention to continue to strive toward the 2% target. Indeed the core inflation (excluding food and energy) remained at 2%[2] in the Monthly Bulletin, July 2008. The inflation expectation from the market is now about 2.5%, as described on page 27 (chart 13) in that document.

Given this evidence the SEMC remains of the view that a reasonable estimate of the inflation applicable to the calculation of the WACC for a BNE investment is 2.40%.

Inflation Consultation Values – 2.4% (Ireland) / 2.4% (UK)

Inflation Decision Values – 2.4% (Ireland) / 2.4% (UK)

[2] Link: http://www.ecb.europa.eu/pub/pdf/mobu/mb200807en.pdf

4. Debt Spread

The 4 July Consultation Paper increased the debt spread from the estimate of 2.0% which applied in 2007 and 2008 to 2.25%. The reason for this increase was the changed conditions for borrowing money at a BBB-rating as a result of the credit crunch and general widening of spreads.

The following response was received regarding the Debt Spread:

Bord na Móna argued that the debt spread was too low and should be closer to 2.75%.

AES argued that the interest rate on debt should be based on prevailing nominal rates. AES commented on the need to consider the cost of arranging finance which could equate to as much as 0.5% of the debt raised.

Consideration of Responses

The calculation of the debt spread was based on an examination of data from the US applicable to BBB rated utilities and from euro-denominated debt issued by UK corporates.

The US and UK debt spread was calculated by reference to Bloomberg data and yielded values of around 2.9% and 1.5% respectively.

The SEMC has decided to retain the broadly mid-point estimate of 2.25%. The SEMC believes that this value is on the high side, but has made this decision in the context of the present turbulence on the debt market. It is the SEMC's view that this value also adequately covers the cost of arranging finance.

Debt Spread Consultation Values – 2.25% (Ireland) / 2.25% (UK)

Debt Spread Decision Values – 2.25% (Ireland) / 2.25% (UK)

5. Equity Risk Premium

In the 4 July Consultation Paper the SEMC explicitly asked for responses regarding the appropriateness of continuing to set the Equity Risk Premium (ERP) at 5.5%. It was noted that other regulatory bodies had estimated the ERP to be below 5.5%, including the October 2007 decisions by the UK's Competition Commission, which estimated the ERP to be between 2.5% and 4.5%.

Several respondents commented on the ERP.

VP&E and PPL argued that the recent decision by the Competition Commission for a WACC for the British Airports Authority's Heathrow and Gatwick airports should not be referred to in this exercise, because those airports are regulated assets and the BNE is a merchant investment.

ESBI argued for retaining the 5.5% ERP in the interest of regulatory consistency.

ESB PG agreed with the use of 5.5%.

BGES argued that the ERP assumptions used in one country and industry cannot be compared to those used in a different country / industry.

NIE ES were supportive of further analysis in assessing the appropriateness of referring to the Competition Commission's decision.

<u>Consideration of Responses</u>

The ERP is a measure of the overall level of risk across the market. It represents the systemic risk which the holder of a fully diversified portfolio would face. It should not be confused with the risk associated with the particular investment in question, or whether the investment is in one industry or another.

While it is true that the calculated ERP may vary across currency zones reflecting the volatility of currency movements, the SEMC is of the opinion that the estimate should not materially vary between Ireland and the UK when real returns are considered, notwithstanding subtleties around currency risk.

The ERP used by both NIAUR and CER in recent price controls is below 5.5%. NIAUR set the ERP at 4.5% (the upper end of the Competition Commissions identified range) for NIE Energy and SONI price controls. The CER set the ERP at 5.25% in its recent price controls for Eirgrid and ESB Networks.

As mentioned in the Consultation Paper the SEMC revisited regulatory documents from recent years in which this question was specifically addressed. Ofcom in their price setting exercise for BT in 2005[3] procured a significant amount of work aimed at quantifying the ERP, concluding that, though significant subjectivity existed around the estimate, a value in the range of 4% to 5% was appropriate at the time.

Having weighed the arguments, the SEMC is of the view that 5.5% is on the high side given recent decisions by other regulators. However the SEMC wishes to allow the benefit of the doubt to fall on the side of a higher value estimate for the purpose of this exercise, so has decided to retain the ERP at 5.5% for the 2009 BNE estimate.

ERP Consultation Values – 5.5% (Ireland) / 5.5% (UK)

ERP Decision Values – 5.5% (Ireland) / 5.5% (UK)

[3] Ofcom's approach to risk in the assessment of the cost of capital, August 15 2005

6. Asset Beta

Several responses were received concerning the Asset Beta.

Bord na Móna argued the Asset Beta should be closer to 0.7 since the plant is a new unit in a fledgling market.

AES noted that 0.6 was at the lower end of the 0.5 to 0.8 range and that no justification for this had been given, arguing that the cyclical nature of EPC prices should tend to push the asset beta upward.

Consideration of Responses

It is clear that a stand-alone peaking generating unit is at the riskier end of energy investments and so it is appropriate for the number to be higher than the range typically applied to regulated businesses such as transmission and distribution, which range around 0.2 to 0.3 in most cases.

The SEMC acknowledges that 0.6 is toward the lower end of the 0.5 to 0.8 range quoted for generation. However, it believes this is justified given the existence of an explicit CPM in which some degree of certainty is granted to generator participants.

The SEMC has decided to retain an Asset Beta of 0.6.

Asset Beta Consultation Values – 0.6 (Ireland) / 0.6 (UK)

Asset Beta Values – 0.6 (Ireland) / 0.6 (UK)

7. Tax Rate

The Consultation Paper proposed using the tax rate applicable in the jurisdiction in which the BNE is located.

AES argued in their response for a nominal European-derived average tax rate to be applied to both jurisdictions rather than the actual jurisdictional rates. They argued that an international investor for whom profits are repatriated would likely face higher tax rates than those applying in either jurisdiction, and consequently would be at a loss under the proposed decision.

AES also argued that a calculated asset beta based on an international comparison (as was done above) was of necessity related to average effective tax rates.

Consideration of Responses

The SEMC accepts that additional investment may come from non-UK or RoI domiciled companies. However it is not of the opinion that this warrants adjustment of the applicable domestic tax-rates. The financial structures which companies make use of in foreign direct investment (FDI) and the regulations governing withheld profits abroad are complex. It is not accurate to suggest that returns on FDI are inevitably fully exposed to the home corporate tax rate. The appropriate tax rate to consider is the applicable rate in the jurisdiction where the investment is made.

Furthermore the SEMC wishes to make clear that it does not consider that the higher tax rate in the UK precludes investment in Northern Ireland compared to the Republic, nor would a generator participant in the SEM base its locational decision on avoiding exposure to these rates. Higher tax rates have offsetting benefits for the other WACC parameters.

The SEMC has decided to retain the proposed decision on the use of real jurisdictional tax rates.

Tax Rate Consultation Values – 12.5% (Ireland) / 28% (UK)

Tax Rate Values – 12.5% (Ireland) / 28% (UK)

8. Plant Life

During the course of the consultation the fact that a plant life of 15 years did not equate to a residual investment value of zero was brought to the attention of the SEMC. This is because a peaker will most likely not require a life extension or decommissioning until after 30 years. Any residual value of the plant (and the value of the site) should be recouped. This value should factor in the site cleanup costs, including dismantling of the plant itself.

The SEMC's consultants advised that a linear depreciation methodology has been used in similar regulatory exercises internationally. It is the case that alternative depreciation methodologies would generally yield a lower residual value than such a linear method. Applying a decommissioning date of 30 years under a linear depreciation model yields a 50% effective residual value after 15 years.

Using the WACC settings described previously, a 50% residual value after 15 years equates to a 17.9% and 15.6% investment residual value in NI and RoI respectively. This deduction would apply to the EPC contract cost, which includes the site, turbine and relevant auxiliary equipment and installations.

While these estimates are based on generous assumptions as to the residual value of the plant after 15 years, the SEMC is of the opinion that it is erroneous to argue that the expected value is zero or negative.

Nonetheless the SEMC is of the view that it is prudent, for the purposes of this exercise, to disregard these benefits as they are subject to uncertainty both as to likely cleanup costs and future market conditions.

The SEMC intends to investigate the issue of residual value and cost components in future exercises in estimating the cost of a BNE Peaker.

9. Resulting WACC

TABLE 2
WEIGHTED AVERAGE COST OF CAPITAL CALCULATION FOR THE 'BEST NEW ENTRANT' PEAKING PLANT FOR 2009

VARIABLE	Consultation		Decision	
	RoI	UK	RoI	UK
Nominal Risk Free Rate	4.58%	4.82%	4.56%	4.97%
Inflation	2.40%	2.40%	2.40%	2.40%
Real Risk Free Rate	2.13%	2.36%	2.11%	2.51%
Debt Risk Premium	2.25%	2.25%	2.25%	2.25%
Real Cost of Debt	**4.38%**	**4.61%**	**4.36%**	**4.76%**
Real Risk Free Rate	2.13%	2.36%	2.11%	2.51%
Market Rate of Return	7.63%	7.86%	7.61%	8.01%
Tax Rate	12.50%	28.00%	12.50%	28.00%
Asset Beta	0.60	0.60	0.60	0.60
Equity Beta	1.83	1.61	1.39	1.25
Cost of Equity	**12.17%**	**11.21%**	**9.74%**	**9.38%**
Debt %	70.0%	70.0%	60.0%	60.0%
Equity %	30.0%	30.0%	40.0%	40.0%
WACC, real Pre Tax	***7.24%***	***7.90%***	**7.07%**	**8.07%**

Impact of changing the gearing to 60% and holding the other parameters constant:

At first glance the reduction in WACC in RoI may seem counter-intuitive, as it is commonly the case that the WACC increases in response to a reduction in gearing when employing the CAPM framework because remunerating equity is generally more expensive than remunerating debt.

While increasing the equity share, the gearing reduction also reduces the financial risk (i.e. the equity beta). This means the premium over the asset beta required by owners also reduces (this can be seen as a reduction in the equity beta).

Critically, in this case, increasing the equity share markedly reduces the per-unit risk of that equity in the RoI tax setting, as seen in the reduction from 12.17% to 9.74% in the Cost of Equity. This reduction in equity risk outweighs the higher weighting of that risk in the weighted average calculation and so the WACC estimate is slightly reduced overall as a result of the change in gearing for RoI.

VII. INVESTMENT COSTS

1. EPC Contract and General Capital Cost Evaluation

Almost all respondents commented on these key parameter estimates.

ESBI argued the estimates were too low, stating that the total investment cost should be closer to €88 million.

BGES expressed surprise that the values have not changed much since 2007 given their experience of how prices have changed over the past two years.

Bord na Móna argued that there was not enough transparency in the development of the Base Cost Estimates, and that the estimates are not sufficiently robust given the Regulatory Authorities' performance over the past few years in making these estimates. BnM went on to call the BNE methodology into question, given the SEMC's acknowledgement of the volatility and uncertainty in estimating these parameters.

PPB expressed surprise that the costs did not reflect rising commodity prices seen over the past year. PPB considered the proposed annualised cost was understated by at least 10%.

PPL argued that the implied price per kilowatt was broadly consistent with 2007 prices, but that their calculations now indicated a higher prevailing price than that proposed by the SEMC.

AES strongly disagreed with the proposed estimates and suggested a consequent annualised final cost of €176.06/kW/year, more than double the SEMC estimate, was more reflective of current conditions in the market for generating equipment.

<u>Consideration of Responses</u>

The SEMC sought further explanation from its engineering consultants on the Base Case Estimates and requested that further investigation be carried out, given the weight of comments received.

In the first instance, the consultants made contact with Siemens directly and verified that the estimate they had made for acquisition of the turbine was plausible. This was done prior to the drafting of the Consultation Paper.

The approach employed by the consultants reflected the approach used for the determination of the best technology and its associated costs for 2007. Regarding the cost breakdown for the selected technology (the Siemens 2000E), the consultants built up the estimated cost for each of the areas identified in Tables 5 and 6 of the Consultation Paper.

The SEMC considers that these tables, together with the detailed descriptions for each item provided within the text of the Consultation Paper, provide a clear and transparent description of the basis for the determination of the costs. The largest cost is the Engineering Procurement and Construction (EPC) cost which the SEMC's engineering consultants estimated based on a combination of:

- publicly available catalogues;
- direct communications with the relevant vendor; and
- their know-how and experience from similar projects on the techno-economic aspects of power plant assets, including use of their database on items such as civil works, electrical equipment, transportation, construction and erection costs and commissioning.

Similar approaches were adopted for a number of other cost elements such as electrical connections and fuel facilities as described in the following sections.

The SEMC note that obtaining quotations from vendors may lead to prices being quoted which fail to reflect the effect of discussion and final negotiation. This is sometimes referred to as 'optimism bias', in that adequate padding must be added by tenderers to price estimates when assessing the plausibility of a new generation project. The SEMC took account of this effect in formulating its estimates for the component costs.

The SEMC has become increasingly aware of the difficulty of accurately estimating the settled capital costs for the BNE peaker in the current climate of volatility and it was for this reason comments were sought on smoothing. Given the range of estimates received from its own sources, which in places are admittedly as wide as 35% for some individual items, the SEMC was encouraged by PPB's and ESBI's estimates, as the former suggests an error of 10% around the original SEMC estimate, while the latter suggests a value that, after the 18% market adjustment to the SEMC Base Case figures, is only around €4 million (~5%) higher than the original SEMC estimate.

Several respondents provided detailed (and confidential) estimates of different elements of the EPC costs. The largest component of these costs is procuring the power train. While many of the estimated costs of other sub-components differed, in some cases significantly, the estimates for the cost of the power train were very similar.

The SEMC has decided not to adjust its Base Case Estimates above what was proposed in the Consultation Paper except as explicitly considered in other sections of this paper (for example the site acquisition as described below). In particular the SEMC is of the opinion that many of the differences in estimates are accounted for by the market adjustment of 18% discussed below.

2. Market Adjustment

NIE ES and AES requested further explanation of the 18% market adjustment in the Consultation Paper.

Consideration of Responses

The Consultation Paper sets out the details of the Base Case including all the cost elements investigated by the consultants and the basis on which these costs were estimated (publicly available data, the experience of the consultants from previous similar projects, information from vendors, discussions with relevant third parties such as councils and land agencies etc).

The derivation of the Base Case was consistent with the approach adopted for the cost derivations for 2007 and 2008. However, as noted in the Consultation Paper, the SEMC recognises that some of these cost elements, particularly the capital costs, are subject to a degree of judgement. The SEMC therefore engaged further consultants to get alternative views on these elements so as to provide the SEMC with additional information upon which to base their estimates for 2009.

In making its determination of the adjustment to be made, the SEMC was aware that the methodologies and judgements as to the prevailing market climate used in estimating the relevant elements varied. Having considered the evidence provided in relation to the various cost elements, the SEMC considered that a mid-point value between the alternative sources would provide the most reasonable representation. This took the form of an 18% uplift on the total capital cost in the Base Case scenario – the market adjustment.

Though the baseline estimates have changed for some line items, the SEMC feels that it is not appropriate to re-compute a mid-point from the range of values received. The rationale for this is that the Base Case represents an estimate of the best achievable price and similar adjustments could be made to the range of reasonable estimates.

The SEMC has decided to retain a market adjustment uplift to its baseline capital investment estimates of 18%. The implications of this, in concert with the revisions in the following sub-sections is discussed in sub-section 7 below.

3. Site Procurement

Several respondents commented on the site acquisition cost estimate.

ESBI, Bord na Móna, BGES and AES argued that the proposed site was too small for the footprint of the plant and its list of additional items (switchyard, tanks etc).

Consideration of Responses

The SEMC reviewed the site size estimate with its consultants and agrees with the respondents that the proposed site size is too small for the plant.

A review by the consultants on the estimate considering requirements for switchgear, fuel storage and other plant associated requirements yielded a site size of 20,000 square metres compared to the original estimate of 4,800 square metres and a subsequent revised Site

Procurement cost of €6.977 million in NI and €3.221 million in RoI. This has been factored in computing the final decision.

4. Electrical Connection

Several comments were received regarding the proposed electrical connection estimates.

VP&E, ESBI, BnM, ESB PG argued that no 110kV nodes could currently accept a 168MW plant, as it was too large.

ESBI further argued that there was nowhere convenient to connect at 220kV without significant cost.

ESB PG further argued that the single circuit 2km link should be replaced with a double circuit or looped-in connection.

Consideration of Responses

The SEMC has reviewed the proposed arrangements with its consultants and the System Operators, and are in agreement that the connection should be changed to 220kV for a plant sited in RoI, particularly given the locations the System Operators have expressed are in need of additional support.

For a plant sited in NI, this argument carries less weight and it is the view of the SEMC that a 168MW plant sited in the meshed 110kV network close to the Belfast load centre (such as Belfast West) would be plausible.

Regarding the single 2km connection, the SEMC accept the view that a double circuit connection offers superior strength and reliability, especially if moving to 220kV and has factored this into the final calculation.

Following discussion with the consultants, the connection in NI has been updated to €3.55 million to be commensurate with a double-circuit 110kV connection and the in RoI to €5.3 million to be commensurate with a double circuit 220kV connection.

5. Distillate Facilities

VP&E noted that the cost allowed for full fuel oil storage and distribution appeared low, and commented that it was not clear how initial fuel oil first fill had been included in the calculations. VP&E also highlighted that fuel degradation did not appear to be factored into the working capital estimate.

Consideration of Responses

In preparing the Consultation Paper, the SEMC concluded that it was appropriate to treat the fuel as working capital since any fuel consumed due to operation would be recompensed through payments in the energy market and that the price bid into the market by the generator would reflect all the associated costs of fuel purchase and delivery to the site, but would not reflect the cost tied up in the fuel on site (i.e. the working capital).

While the modelling work undertaken by the SEMC indicated that the BNE would be scheduled for operation for only a handful of hours, it is generally expected that the BNE will operate during the year for the purposes of constraints and that consequently it is likely that the distillate will be consumed ahead of any significant degradation.

The SEMC has thus decided to retain its proposed estimates and treatment for the distillate facilities and first fill.

6. Interest During Construction (IDC)

Some comments were received in supplement to the formal submissions that the SEMC's interest during construction estimate appeared low.

Consideration of Responses

In the original calculations, the SEMC allowed a total construction time of twelve months for the unit. This was based on judgement and the experience of its consultants, noting that six months is usually sufficient for an aero-engine by comparison.

Respondents argued that a lead time of two years needed to be allowed prior to the start of construction, followed by a six month period to complete the project upon delivery of the unit.

The SEMC recognises that there are lead times in the procurement of gas turbines and that some allowance should be made. However, the SEMC considers two years to be excessive given that slots can be booked in advance for delivery. Based on the recent experience of its consultants, the SEMC considers a total time of 15 months to be a more reasonable estimate.

Using this updated estimate for the construction time and the revised WACC (discussed previously) yields IDC estimates of €3.444 million for NI and €2.934 million for RoI. These values have been factored in to the calculation.

7. Investment Costs Relative to Consultation

TABLE 3
INVESTMENT COST ESTIMATE FOR 'BEST NEW ENTRANT' PEAKING PLANT LOCATED IN NORTHERN IRELAND
(€ '000S)

	Consultation	**Decision**
Site Procurement	**2,244**	**6,977**
Pre Financial Close Costs		
Owner's manpower costs up to contract award	893	893
Financial, legal costs, engineering, consultancy and EIA	1,191	1,191
Total Pre-Financial Close Costs	**2,084**	**2,084**
Post Financial Close Costs		
E.P.C. Contract (including contingency)	59,531	59,531
Electrical Interconnection	2,550	3,550
Distillate Facilities	906	906
Water Injection (NOx reduction)	0	2,200
E.P.C Total	**62,987**	**66,187**
Other costs		
Owners manpower during construction	1,191	1,191
Taxes, insurance during construction	417	417
Purchased electricity, fuel during construction	298	298
T&SC Fees	6	6
Contingencies	985	1,114
Interest during construction	2,576	3,444
Total Other costs	**5,473**	**6,470**
TOTAL INVESTMENT COST	**72,788**	**81,718**
TOTAL ADJUSTED INVESTMENT COST	**85,890**	**96,427**

TABLE 4
INVESTMENT COST ESTIMATE FOR 'BEST NEW ENTRANT' PEAKING PLANT LOCATED IN THE REPUBLIC OF IRELAND
(€ '000S)

	Consultation	Decision
Site Procurement	**1,343**	**3,221**
Pre Financial Close Costs		
Owner's manpower costs up to contract award	893	893
Financial, legal costs, engineering, consultancy and EIA	1,191	1,191
Total Pre-Financial Close Costs	**2,084**	**2,084**
Post Financial Close Costs		
E.P.C. Contract (including contingency)	59,531	59,531
Electrical Interconnection	2,550	5,300
Distillate Facilities	906	906
Water Injection (NOx reduction)	0	2,200
E.P.C Total	**62,987**	**67,937**
Other costs		
Owners manpower during construction	1,191	1,191
Taxes, insurance during construction	298	298
Purchased electricity, fuel during construction	298	298
T&SC Fees	6	6
Contingencies	930	1019
Interest during construction	2,328	2,934
Total Other costs	**5,051**	**5,746**
TOTAL INVESTMENT COST	**71,465**	**78,988**
TOTAL ADJUSTED INVESTMENT COST	**84,329**	**93,206**

The increase in the contingency estimates in the tables above relative to the Consultation Paper is commensurate with the stated increases in the estimated line item costs that the contingency covers.

The combination of these various revisions and the decision to retain an 18% market adjustment to the base case estimates has resulted in an increase compared to the Consultation Paper in the total capital investment cost in RoI of 10.5%, and in NI of 12.3%.

VIII. Recurring Costs

1. Operation and Maintenance

The following comments were received regarding the Operation and Maintenance (O&M) cost estimate:

ESBI posed a specific query about variable O&M which is addressed in the detailed responses in Appendix 1.

BGES queried on what basis the long term service agreement (LTSA) cost was reduced by 10% compared to the 2007 decision.

BnM requested additional detail.

AES argued the O&M estimates were too low by at least five-fold.

Consideration of Responses

The LTSA estimates for 2007 were based on a different machine (the Alstom 13E2) and estimated by the Regulatory Authorities at that time. It is appropriate to consider variables of this nature.

AES's estimates are substantially higher than the SEMC's or those made by other respondents, some of which were very close to the value determined by the SEMC. However, the SEMC notes that AES's LTSA estimate is pro-rated against a higher EPC estimate. Consequently any difference in EPC will also be reflected in LTSA costs.

The SEMC note that the coverage of an LTSA can vary widely from a basic LTSA covering supply of spares, assistance with maintenance planning and technical advice, through to a more comprehensive LTSA covering matters such as scheduled and unscheduled maintenance, special maintenance and provision of a full-time service manager. LTSAs also vary depending on the operating regime of the plant. The scheduling analysis undertaken for the purposes of determining inframarginal rents (see later) shows the BNE plant running for very few hours. Consequently it is to be expected that the utilisation for the plant even for constraint conditions is likely to be low, perhaps only a few hundred hours.

Given the above and after due consideration, the SEMC is satisfied that the figure quoted in the Consultation Paper is a reasonable estimate of the costs.

2. Insurance and Miscellaneous

BGES queried the apparent reduction by 45% compared to the 2007 decision for the insurance estimate.

AES disagreed with the lower insurance estimate compared to the 2007 decision, arguing that the lower plant size could not justify the decrease.

<u>Consideration of Responses</u>

The SEMC reviewed the estimates for recurring insurance, as well as for insurance during construction independently of the process employed in the 2007 calculation and is satisfied that those estimates are reasonable for a project of this nature.

3. Rates

BGES queried the reduction by 30% compared to the 2007 decision for the rates estimate.

BnM requested additional detail.

AES disagreed with the lower rate estimate compared to the 2007 decision, arguing that the Rates should increase at least by inflation and that the lower plant size could not justify the decrease.

<u>Consideration of Responses</u>

The determination of Rates for the two jurisdictions are very similar in that each applies a scaling factor to a Rateable Value for the plant (which itself is a multiplier of the installed capacity of the unit).

The estimation performed for the 2007 calculation was based on that employed for the BNE Baseload work previously carried out by the Commission for Energy Regulation, scaled to reflect the size of the BNE peaking unit.

The estimates for Rates for 2009 are based on information sourced directly from communications with local authorities in the areas in which the BNE peaking plant would likely be situated.

The SEMC considers this process to be as accurate for estimating the probable rates bill as is reasonably achievable without proceeding to construction. The SEMC considers the values for 2009 set out in the 4 July Consultation Paper to be the appropriate estimates for a BNE peaking plant.

4. Transmission and MO Charge

AES agreed with the estimates for the transmission charges.

<u>Consideration of Responses</u>

The SEMC has retained all these estimates.

5. Fuel Working Capital

VP&E made a comment regarding the degradation of distillate oil over time and that this factor was not allowed in the calculation of working capital. Further, VP&E made a comment that it was not clear how the initial fuel oil first fill had been included in the calculations.

Consideration of Responses

Matters such as working capital tied up in distillate contained in the on-site tanks was determined using the calculated WACC, a published distillate reference price and an estimate of the required quantity of distillate to enable the unit to operate at full-load for 4 days.

The SEMC reviewed the detailed calculations with its consultants and has confirmed that the quoted estimates are reasonable.

IX. Infra-marginal Rent and Ancillary Services

Some comments were received regarding the Ancillary Services estimate:

ESBI did not agree that these deductions should be made in the first place – this is addressed in detailed responses in Appendix 1.

BnM highlighted a lack of detailed explanation around the Ancillary Services estimate.

Consideration of Responses

The estimation of Ancillary Service revenue differs between the two jurisdictions because the current arrangements are different and the way forward on harmonisation has yet to be determined.

In Northern Ireland the Ancillary Services payments are encompassed within the System Support Services Agreements (SSSAs) and dis-aggregation of the Ancillary Service payments from the total SSSA payments is difficult. Following a review of the revenues NI generators actually derive through the SSSAs, the SEMC considers that the estimate of Ancillary Service revenue provided in the Consultation Document (equating to €5.05/kW/year) was a reasonable estimate for the size of the Siemens unit and the assumptions regarding its operating capabilities (specifically its Forced and Planned outage rates).

The Ancillary Service revenue estimate for the Republic of Ireland in the Consultation Paper was based on the payment rates set out in the Eirgrid Statement of Charges and Payments for Ancillary Service Providers 2008[4] with an adjustment applied to inflate the rates to an estimate of 2009 prices. The key services in respect of the Siemens plant (which, as noted in the Consultation Document, is not expected to operate significantly) are Reactive Power and Replacement Reserve. Payments for all remaining services are dependent on the unit being

[4] Available on the Eirgrid website www.eirgrid.com

synchronised and were therefore set to zero. Note that the elements of payments for Reactive Power and Replacement Reserve services which are also dependent on synchronisation, were also set to zero.

Employing the same assumptions regarding Forced and Planned outage rates as for the Northern Ireland calculations and accounting for the “over-provision scaling”[5] within the Eirgrid arrangements, resulted in the estimate for the Ancillary Services revenue for the BNE peaking plant in RoI of €1.182 million.

In reviewing the calculations it was identified that the capacity of the unit had been over-stated in error in this calculation. Correcting the unit capacity to the averaged net power output for the plant has resulted in an estimated Ancillary Service revenue for the BNE peaking plant in RoI of €1.061 million (or €6.69/kW/yr).

X. VOLATILITY - EPC AND WACC SMOOTHING

Several respondents commented on the SEMC’s ideas regarding smoothing of the WACC and / or EPC estimates.

ESBI put forward a method that would apply a different technique depending on whether the recent trend has been increasing or decreasing.

IBEC put forward some summarised suggestions for smoothing out the total BNE Price, including a five-year rolling average with a ratchet arrangement to keep the average price from falling, and /or applying a fixed price for new entrants.

Bord na Móna put forward a detailed criticism of the regression line analysis in the Consultation Paper.

ESB PG argued that current spot prices should be taken and then inflated in the future, citing the Airport Authority approach in the form of a ‘construction index’.

PPB argued that only spot prices should be used as smoothing could lead to under-investment if the price is rising.

PPL stressed the need for the smoothing approach to be uniform across the parameters under consideration.

AES argue that historical averages should be used for all the parameters in the WACC and that changes over time should be trackable.

[5] Note that this addresses the point made by ESB Power Generation regarding scaling of the money available across the service providers – i.e. such scaling has been considered in estimating the AS revenues.

Consideration of Responses

The detail of the various specific suggestions put forward are addressed at Appendix 1 rather than being responded to here.

While several respondents put forward some interesting proposals, these were not sufficiently detailed to warrant concrete changes to reduce potential volatility in the Annual Capacity Payment Sum at this stage.

The SEMC has to make a judgement in calculating the EPC estimates for a hypothetical BNE Peaking Plant. In forming this judgement it has been necessary to rely on the advice of expert consultants. However, the advice of consultants will also vary depending on views regarding developments in relevant markets, prudent levels of contingency, etc. It is the aim of the SEMC to assess how these can be standardised in advance of future calculations of the BNE parameters.

The SEMC sees merit in some of the arguments put forward by several participants about the impact of volatility caused by the annual recalculation of the capacity pot. However, PPB’s argument that a smoothing mechanism could lead to periods of under-incentivisation is also valid. These concerns would have to be considered in detail before any mechanism to reduce volatility along the lines suggested in the Consultation Paper were developed.

The SEMC will consider these issues (including the submissions received as part of this consultation) further. In this context it will consult with industry on the most appropriate means to deal with the issues, but no smoothing method is employed in the calculations herein (with exception of the Nominal Risk Free Rate as described previous).

XI. FINAL BNE FIXED COST

The final derivations of the BNE Fixed Costs for 2009 are shown for NI and RoI in the tables below.

TABLE 5
FIXED COST ESTIMATE FOR 'BEST NEW ENTRANT' PEAKING PLANT LOCATED IN THE NORTHERN IRELAND
(€ '000S)

Capital Cost		
Capex (Base)	€ '000	81,718
Capex (Adjusted)	€ '000	96,427
Plant life	years	15
WACC	% p.a.	8.07%
Fixed Costs		
Operations and Maintenance	€ '000	1,176
Transmission and SEMO charges	€ '000	846
Insurance and Miscellaneous cost	€ '000	1,008
Rates cost	€ '000	578
Fuel Storage	€ '000	187
Annualised Capital plus Fixed Costs	**€/kW**	**95.26**

	€/kW/yr
Unadjusted BNE Cost	84.38
Adjusted BNE Cost	95.26
Energy Market Infra Marginal Rent	(0.0007)
Ancillary Service Revenue	(5.05)
Final BNE Cost	**90.21**

TABLE 6
FIXED COST ESTIMATE FOR 'BEST NEW ENTRANT'
PEAKING PLANT LOCATED IN THE REPUBLIC OF IRELAND
(€ '000S)

Capital Cost		
Capex (Base)	€ '000	78,988
Capex (Adjusted)	€ '000	93,206
Plant life	years	15
WACC	% p.a.	7.07%
Fixed Costs		
Operations and Maintenance	€ '000	1,176
Transmission and SEMO charges	€ '000	935
Insurance and Miscellaneous cost	€ '000	1,008
Rates cost	€ '000	1,315
Fuel Storage	€ '000	164
Annualised Capital plus Fixed Costs	**€/kW**	**93.81**

	€/kW/yr
Unadjusted BNE Cost	83.92
Adjusted BNE Cost	93.81
Energy Market Infra Marginal Rent	(0.0007)
Ancillary Service Revenue	6.69
Final BNE Cost	**87.12**

XII. CAPACITY REQUIREMENT

This section details the individual components and calculation that has been carried out for the quantification of the 2009 Capacity Requirement.

1. Consultation

Several respondents queried the brevity of the Capacity Requirement section in the Consultation Paper and asked as to a potential separate consultation on this parameter of the ACPS calculation.

Some respondents also verbally requested that more information be made available regarding the Capacity Requirement calculation process to facilitate research and replication by parties outside the Regulatory Authorities / System Operators.

The SEMC will not be issuing a consultation on the Capacity Requirement for 2009 because the methodology, inputs and settings of the key underlying parameters for the calculation process were extensively consulted on in the 2007 and 2008 process.

With regard to the request for additional information about the calculation process, the SEMC has compiled an explanatory note in Appendix 2 which sets out in additional detail the process and provides some examples which it hopes will improve the perceived transparency of this element.

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 Regulatory Authorities' (RA's - CER and NIAUR) 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 and 2008 Capacity Requirement. As anticipated in the initial consultation and decision papers, the same parameter settings have been used in the calculation for the 2009 Capacity Requirement. The following sections describe further each of these parameters.

3. Generation Security Standard (GSS)

In AIP/SEM/111/06 the Regulatory Authorities (RAs) stated that a single GSS for the entire island would be applied following detailed research by the System Operators 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 SEMC for the 2009 calculation.

4. Demand Forecast

As laid out in the Decision Paper AIP/SEM/07/13, the demand forecast was formulated by the System Operators to reflect the 'median' load growth scenario for the calendar 2007 and 2008 years during the process employed in 2007.

For the 2009 Capacity Requirement calculation, this process has been repeated. The System Operators were asked to provide half-hourly demand forecast profiles for the median-growth case (commensurate with the 2007 process). Care was exercised to ensure that the jurisdictional traces were harmonised (i.e. based on the same reference year, 2006, and day-shifted to align on a day-by-day basis).

The SEMC assisted in combining these jurisdictional load traces into a single, all-island demand trace for input to the CREEP calculation engine (described below).

5. Generation Capacity

AIP/SEM/07/13 discussed the merits of various methods of quantifying unit participation and set size for the forecast year, and concluded with a decision that the most appropriate method was to request the data directly from participants.

This was largely unnecessary for the 2009 calculation as this data was already collected as part of the Directed Contracts process that took place in early 2008. As such this data was taken in the main from the Directed Contracts database, with discussion with System Operators and participants as needed in supplement.

6. 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 2009 Capacity Requirement process.

7. Forced Outage Probabilities

The Decision Paper AIP/SEM/07/13 sets out the RA's 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%.

This Decision Paper makes very clear that the computed value was to be used in calculations going forward (page 23). The SEMC has carried this figure forward in its quantification of the 2009 Capacity Requirement.

8. Treatment of Wind

The Decision Paper AIP/SEM/07/13 explains the RA's decision to treat wind as a netting trace against the load trace. This process, employed in the 2007 and 2008 processes, has been repeated by the SEMC in the 2009 process.

Individual wind output traces were provided by the System Operators and harmonised in similar fashion to the 2006 traces. The wind traces were built upon the same reference year and aligned on a day-by-day basis with the load traces described earlier.

9. CREEP Calculation Process and Capacity Requirement

Having collected together the various input data points, the System Operators ran the iterative CREEP software process to calculate the 2009 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 that followed.

The process is discussed in more detail in Appendix 2.

Having implemented the process exactly as per the 2007 decisions and process, the Capacity Requirement for 2009 is **7,356MW**.

10. Maintenance of Capacity Requirement Method

Several of the respondents to this consultation process repeated arguments which had been made previously, arguing that the methodology used to calculate the Capacity Requirement suffered from significant shortcomings. The SEMC is of the opinion that reviewing these settings within one year of the establishment of the new market would have been inappropriate. However, the SEMC is also aware of the need to review the extent to which the SEM is operating effectively. In this context the SEMC will continue to assess the Capacity Requirement settings as the market matures. Any proposal to amend or alter the settings will be the subject of full consultation with participants.

XIII. APPENDIX 1 – DETAILED RESPONSES TO INDUSTRY COMMENTS

ESBI	
Tech Choice – Did not agree with choice of Siemens; arguing that an aero derivative is superior to this. ESBI's modelling indicates that highly flexible Aeros are required on the island in the face of increasing wind as opposed to heavy duty plant.	There is merit in the argument that Aeros are more flexible, but the 2000GT is also highly capable in this department. The SEMC acknowledges that both are plausible options to a rational investor. The requirements of the BNE were discussed with the TSOs who are in the best position to make an informed judgement about the system requirements for peaking capacity.
Market Engine – does not schedule peaking plant even when its bid price is below the SMP. This is backed up by Plexos runs.	It is possible that the uplift function is not being properly captured in the ESBI model, but this statement lies outside scope of this paper.
Costs – These are understated based on ESBI's extensive international experience. The EPC should be closer to €88m compared to the €71.465m in the Consultation Paper.	Note the 18% market adjustment to the Base Case estimate; this makes the SEMC estimate in fact very comparable to the ESBI estimate (within about 5%).
Site – Is not big enough for footprint of 2000GT. Argument that the SEMC have not considered noise levels at boundary and the visual impact.	The SEMC has reviewed the site size up to 20,000 sqm as per the main document.
Connection – argue that 110kV is not appropriate given the set size; also that there is nowhere convenient on the island at 220kV without significant cost	The SEMC has reviewed the connection arrangements as per the main document.

OPEX – Clarification sought; is Opex allowed to vary year on year? What are the allowances for start ups, ramping and shutdowns?	The BNE calculation does not include avoidable costs such as maintenance caused by start-up, ramping and shut-down as these should be bid into the energy market. Only the fixed annual component of O&M is estimated, including contractor fees, inspections etc.
Deduction of Ancillary Services and Infra Marginal Rent – ESBI do not agree that these deductions should be made	The rationale behind this was covered under consultation in 2007 and will not be revisited as part of this work.
Method for smoothing EPC costs – ESBI suggest a different method depending on whether prices are rising (use spot) or falling (use average). ESBI suggest standardised use of a program like GTPro and more transparency around each component. Adequate contingency should be built in.	The SEMC in first thought does not support the idea of two different methods that favour a higher valuation depending on whether the recent trend has been upward or downward, as this holds no financial or mathematical substance. There is some concern that the standardisation of the process using commercial database packages would remove key human discretion required during periods of volatility (as per the current situation) but the SEMC sees this as a good idea for potential assistance in carrying out the regulatory duty. Contingency has been adequately addressed in the estimates in the SEMC's view.
Equity Risk Premium – Should continue to use 5.5% to maintain regulatory consistency	As per main body.

WACC Method – Expressed support for a) or b) over option c). Would prefer a reliable forward-looking projection if it were available	The SEMC is inclined to agree but did not observe any solid development of possible smoothing theory in the Consultation responses.

IBEC	
EPC Method – Some interesting in principle ideas provided	Though ideas are interesting in principle, the SEMC was hoping for some formal financial theory that could be used to potentially justify the smoothing.
Several Comments on CPM Design and ongoing concerns	These are not addressed in this decision document but will be carried forward in strategic development as discussed in the Summary of Decisions.

Bord na Mona	
Costs – argued that not enough transparency in development of Base Case Fixed Cost per year Argued the screening analysis should not be on base case but median; also the reason for discounting 13E2 not explained clearly BnM noted the recurring costs are lower than in the 2007 calculation,	Additional description of these elements is provided in main body

and requested more explanation	
WACC – Expressed surprised at the fall in WACC compared to last year. Observed that this is contrary to global conditions Spot valuation of nominal risk free rate is not appropriate as daily variance is significant relative to long term. BnM consider 4.8% more appropriate than 4.58% Argue the debt spread should be at least 2.75% Argue the Asset Beta should be closer to 0.7 for a BNE peaker as it is a new unit in a fledgling market so should be at the top end of the 0.5 to 0.8 scale Argue the pre-financial cost is underestimated; experience dictates values closer to €2m	The estimates are based on prevailing market conditions and data as described in the main document. The nominal risk free rate has been re-calculated as an average of 31 recent days prior to publication of this document. Addressed in main body The SEMC judgement here was taken in context of the secure revenue stream of the SEM CPM compared to an energy only market, justifying a value at the lower end of the scale Addressed in main body
Site purchase – argue the estimate is too low to accommodate all the required infrastructure. Argue an estimate of at least €3m is appropriate	See previous
Connection – argue that a 110kV connection is not appropriate as the unit is too large. Suggest an estimate based on 220kV which should bring cost up to around €4m	See previous
BNE implementation – BnM offer comments to effect that the EPC	The SEMC accepts the challenge this project presents, as several

price estimates are not sufficiently robust, looking across the evaluations made by the RA's since 2006 and the international experience. An acknowledgement is made that the technology choice change relative to last year makes comparison difficult. **Acknowledgement by RAs of market volatility calls entire BNE estimation method into question.** BnM argue this is evidenced by some errors on estimates of up to 36%	dozen key parameters must be estimated prudently on a hypothetical basis. Examination of means to improve robustness on the EPC parameter estimates is of interest to the SEMC in strategic development. The SEMC is aware that volatility has a negative impact on the replicability of the CPM calculation methodology. The SEMC is vigilant to the emerging regulatory challenges in this regard, indeed this was the motivation for requests on the concept of a smoothing process. This matter will be explored further in strategic development.
Ancillary Service Revenues – argue that not enough transparency was evident in how this was estimated	More detail is provided in main body
EPC Smoothing – BnM offer a detailed criticism of regression lines and analysis Argue that volatility in form of infra-marginal rent and recurring costs is more critical than the elements the SEMC is considering	The SEMC accepts the analysis on this aspect in the Consultation Paper is very broad, but this was not intended as a proposed decision; merely a stimulus to spark constructive comment from industry. BnM make well constructed criticisms of the options in the paper but do not suggest a better or more formal smoothing approach Infra-marginal Rent is a source of potential transparency and volatility issues and this is known to the SEMC, and in similar fashion to the above will be carried forward in development.
Capacity Requirement - argue that this should be subject of equal scrutiny as the BNE.	This is addressed in the main body.

Argue that the implied continuance of 4.23% FOP yields a margin at peak of 3.5% which is unrealistic, and that the target should be revised.	Revisions to the key parameter settings such as the target FOP or the Security Standard would take place in the context of rigorous industry consultation. Accordingly the SEMC intends to open discussion on these aspects as part of its strategic development.
CPM Design – BnM raise **s**everal key points raised regarding the long-term stability of capacity pot sizes and the need to address volatility holistically	Some of these fall outside scope of this paper. The SEMC will take these and related comments from other participants forward in strategy planning.

Bord Gais	
Costs – BGE expressed surprise that the values have not changed much since 2007, noting their experience indicates that costs have increased significantly over the past 2 years.	See previous comments on Costs. It is difficult to respond to comments that are essentially 'our experience indicates…' that are not supplemented with data or references.
Tech Choice – BGE expressed surprise the SEMC discounted the 13E2 when the IPPC directive on BAT was used to select it last year from amongst the contenders.	The definition of 'Best' is of course multi-faceted and BAT and efficiency are important. The SEMC have however made a judgment regarding the additional per-unit cost associated with the 13E2 relative to the 2000GT in deciding to reject it this year.
Fuel Choice – BGE disagree with distillate; arguing the plant should be fired on gas. BGE argue capacity booking is not problematic and short term products are available	This is addressed in the main body

WACC – BGE expressed surprise in the 0.5% reduction compared to last year given the current economic climate Inflation – requested a source for the ECB figure of 2.4%. BGE note that the CER paper on Transmission Allowed Revenues uses 3.4%. BGS analysis indicates 3.5% is appropriate. Equity Risk Premium – did not agree that ERP in one industry in one country can be applied to a different industry in a different country Gearing – did not agree with 70% for a BNE peaker, arguing the value should be closer to 50%. Noted that in 2005 CER used 50% for ESB Networks	The estimates are based on prevailing market conditions and data. This is specifically discussed in the main body See main body comments. As previous
Site – Do not believe the 50% reduction compared to 2007 13E2 is achievable. BGE also question the size of the site.	As previous
LTSA – BG enquired as to what basis the has LTSA reduced by 10% (this is imputed assuming the 1.176m includes Owner's general and admin) compard to the 2007 calculation. Insurance and Rates – BGE requested explanation as to reductions of 45 and 30% respectively on these components compared to last year	Addressed in main body Addressed in main body

ESB PG	
Tech Choice – did not agree that 2000GT is the best choice, and expressed surprise that smaller aero-derivative machines have been excluded. PG argue that larger numbers of small machines are much better for generation adequacy than a few large machines, and that the small machines should not be discounted on grounds of their lower output. Questioned lower weighting of IPPC BAT	The value of having several small plant with independent failure profiles is well known to the SEMC and it was for this reason the smaller units were considered in a 2x configuration in order to meet the SO's preferred parameters. Though the Trent 60DLE in this configuration performs well as a peaking investment, it is considered in the SEMC view, weighing all aspects of the investment, to be an inferior choice for the rational investor compared to the Siemens. See previous on this
Start-up Time – PG understands the Siemens takes 20-39 mins or even 40 mins to start but that Siemens have been working on decreasing the time below 20 mins, but argue that it is unlikely these improvements are built into the SEMC estimate	The SEMC's consultants have confirmed that cost estimates are for a 20 minute start time
Emissions – offer detailed criticism of emissions assumptions; arguing the estimated emissions of 50mg are too low, and should be around 165 without reduction gear. Argue that a rational investor would not limit themselves to 500 hours due to an environmental constraint	Detailed engineering considerations in main body, water injection has been added to the capital cost
Connection – State that typical ratings on the 110kV network are in the range of 137 – 164 MVA according to the Transmission Forecast Statement, so the BNE should be connected at 220kV. PG also argue that a single circuit 2km connection is inadequate, that the	See main body decisions

connection should be looped-in or on 2km of double circuit	
Impact on Wind – argued the peaker should be small enough to locate on 110kV remote areas to replace the wind when its fuel is not available	Discussions with the TSOs have not indicated a need to have a small peaker located in a remote area. The network is managed as a whole, so losing wind in one location can, especially on a small network, be compensated by new generation in another location.
AS Estimate – argued that this should not have gone up compared to last year as the AS pot is not growing significantly and there are more plant on the system now, so the estimate should go down	There is not an Ancillary Services Pot. Although the arrangements differ in NI and RoI they are both payable services – i.e. if the SO needs the service it strikes a contract with providers and pays according to the rates in the contract. The SOs have a budget for AS that they try and work to but it is not a fixed pot as for the CPM. Additional detail is provided on the calculation in the main body
EPC Method – Current spot prices should be taken and inflated to the cost in the future as done in the CC Airport work in the form of a construction index. Index could be in excess of CPI	See previous
Equity Risk Premium – Agree with 5.5%.	See main body
WACC Method – Historic values should not be used to predict the future so disagree with options b) and c). Current method is most appropriate	No smoothing method is used except for the Nominal Risk Free Rate as described

Bord Gais Networks	
Fuel Choice – Should be gas rather than distillate:	
3 shippers have been using the within-day products (1:00am)	3 does not seem many though what would constitute a healthy number is not intuitively clear
No congestion on NI network makes interruptible product almost the same cost as firm, because the probability of interruption very low	This would not be the expectation at equilibrium
CAG in 2010 will result in new short term products	The peaker is operating in 2009 which tends to lessen the benefit somewhat (recognising the costs are spread over 15 years).
13% of throughput is presently through secondary trading. 8 shippers and new entrants are using this facility.	The SEMC agrees there is some evidence of utilisation which is encouraging. However it remains difficult to assess whether the market is liquid.
Gas capacity should be included in SRMC so should not enter into the BNE fixed cost calculation	Gas capacity was decided as a fixed cost item under the second period of consultation on the BNE in 2007.

PPB	
FUEL CHOICE – PPB agree that tradability of gas in RoI does not facilitate avoidance of fixed gas capacity costs. No mention is made of NI	The SEM agree for the purpose of this exercise

Emissions – Decision to exclude NOx reduction not based on any rigorous analysis. Could misalign with BAT	See previous comments and detailed main body
Costs – Surprised price does not reflect commodity price rises seen over past year. PPB considers the proposed €81.24/kW/year is understated by at least 10% Cost – should be inflated to 2009 if quoted for 'end of 2008' – included in the 10% above	The revised value accounting for agreed changes brings the SEMC estimate up very close to what PPB are implicitly advocating See previous
Capacity Requirement – PPB inquired as to consultation on this element, arguing the availability targets have not been met since SEM start Raised a query regarding non-firm access plant being paid the same as those with full access, inferring meaning the CR should be higher	See previous Non-firm here does not have the usual meaning. In this context it means that a plant cannot export full capacity all of the time but can, if the need arises, export full capacity for a short time. Thus no deduction is made to the capacity payments for such units.
EPC valuation – Only spot prices should be used as smoothing could lead to under-investment if the price is rising.	The SEMC's working policy is not to pursue smoothing because it seems clear there is no immediate financial basis for doing so.

PPL	
Tech Choice – No objections to the 2000GT Eliminations – argued the logic in Section IV of the Consultation Paper is inconsistent; and that is not clear how the machines in Table 1 were chosen. PPL query the absence of GE LMS100 (for example) Double units – queried why these have not been evaluated for any plant other than DLE	The units presented are a shortlist of plausible contenders from several plant evaluated by our consultants. Indeed there are many other plausible machines that were eliminated from detailed analyses early in the process as they were clearly inferior in one or more key areas to those in the short list. Addressed in main body
Costs – Imputed €501/kW is generally in line with 2007 prices. PPL spot estimate of €600/kW may not be appropriate to use, but argument is made that it should be clear at what time the estimate was made	The estimate in the Consultation Paper was made during May and June of 2008 with assistance from the SEMC's consultants
EPC and WACC smoothing – Stress the need for the approach to be the same for both and for all cost items to be treated the same.	Agree in principle though it must be recognised that some data points have vastly different environs; estimating forward inflation is very different to estimating site purchase cost for example
Equity Risk Premium – Does not agree with the use of the Airport example. BNE is a merchant plant rather than regulated asset as is the case for airports.	See previous comment on theory of ERP

Gearing – 70% not achievable for a merchant independent peaking plant. Regulated market in US has long standing leverage of 50%. Arguments provided against using the three examples as per the Consultation Paper, and that a more realistic gearing would be around 25%.	This this is further addressed in main body

AES	
SEM Legal Framework – Argued a weakness in that SEMC is not bound to accept representations	This will not be addressed here
Costs – The price of €81.24/kW/year does not seem credible given EPC prices have continued to increase steeply through 2007 and 2008. Increase in the cost of new capacity may be an unanticipated outcome of SEM design Input from consultants should be fully published	See previous Outside the scope of this document This consultation has already laid out significant detail of the estimated component costs compared to last year, also more detail is given in this decision.
Tech Choice – surprised that 20 min start time is considered efficient; given island settings and increasing wind penetration	Point addressed in main body
Cost Components – Mott Macdonald specified values in contrast to	See points above.

SEMC estimates	Site size estimate of 1.2 ha is commensurate with other submissions received and has been considered.
Ancillary Services – made a point about the deduction being homogenous across generation types	It is somewhat unclear the point being made. The deduction of AS revenue applies only to the revenues for the specific BNE plant, regardless of the AS mechanism in place for other plant.
Forced and Planned Outage Rate – argued that constraining-on will cause higher stress and higher rates	The SEMC doesn't consider this hypothetical situation to be material to the base assumptions for these parameters
Fuel Choice - argues that the investor will lose money if he invests in a gas-fired peaker due to the issue of fixed gas transportation cost recovery	This project is being evaluated on distillate because this is considered the cheaper option given the lack of tradability of the gas capacity charge. The viability of a new gas project relative to the 2000GT firing on distillate is not the focus of this paper.
Specific Comments – offered extended commentary from academic advisor on uncertainty and principles of estimating financial parameters	These are useful research findings which the SEMC will take forward in strategy planning but do little to assist the evaluation of the plausibility of the specific estimates. On specific line items including gearing, beta and ERP, the SEMC has decided as per the main body
WACC Smoothing – Historical averages should be used for all the parameters and changes over time should be trackable **Asset beta –** 0.6 chosen in the lower half of the 0.5 to 0.8 range,	View noted but not supported by the remainder of the submission in the SEMC's view Given the existence of a CPM the SEM is thought notionally to be less

further explanation requested **Gearing –** Should be lower than 70% **Tax Rate –** argues use of existing rates is discriminatory to international investors.	risky than an energy only market, hence the decision to choose a value at the lower end of the scale. See previous This was explored in 2007 and it is still deemed that no bias exists in using the prevailing tax rates in the two jurisdictions. Properly modelled, it is seen that the choice between NI and RoI is very close and this is despite the large difference in the CRT values between the jurisdictions.
Capacity Requirement – argue the implied margin of 5% is too low	See previous
CPM Design – Risk of CPM disappearing during the 15 years not considered 'Tagging' and other approaches suggested for specific plant	It is not at all likely that the CPM will simply be discontinued without suitable replacement by other prudent mechanisms, but this is outside the scope of this paper This is not being entertained in this Decision Paper but all suggestions of this nature will be carried forward in SEMC forward strategy planning

NIE ES	
Market Adjustment – further clarity requested on the 18% adjustment. Requested clarification as to whether the adjustment applies just to the cost of the turbine or to all investment costs Requested clarification as to whether the base case represents the lowest estimate received	The 18% adjustment was based on two independent reputable consultancy sources. The midpoint is determined by these two estimates. The adjustment applies to the entire capital cost, but not the recurring costs. The base case does represent the lowest estimate received. A separate independent estimate was obtained, which when a mid point was taken, yielded an effective growth of 18% to the baseline figures.
ERP – Recognise subjectivity in assumptions. Supportive of further analysis to consider appropriateness of the 2.5 to 4.5% ERP	Addressed in main body

XIV. Appendix 2 – Capacity Requirement Sensitivities and Process

Disclaimer: The SEMC have decided to release these sensitivities to facilitate improved transparency of the CREEP model behaviour. The input parameters used in these sensitivities do not represent minded-to settings and are illustrative only. By publishing this data the SEMC does not commit to providing additional sensitivities in the future, as these are largely a by-product of the development process and are calculated courtesy of the System Operators over and above their agreed duties in this process.

Several scenarios were run in 2007 during the research process, and due to a number of subtleties around data availability and internal timescales, further runs have been completed by the System Operators this year beyond those required for the calculation process.

<u>2007</u>

Sensitivities to the Generation Security Standard (GSS) and Forced Outage Probabilities (FOP) are illustrated below. In all six studies, all the inputs are identical except for the GSS and target FOP.

Table 7
Capacity Requirement Sensitivities 2007

Study	FOP % (non-IC)	Adequacy Criterion (LOLE hrs / year)	Peak Market Load (MW)	Capacity Requirement (MW)
ALL01_642_6	6.42	6	6584	7272
ALL01_642_7	6.42	7	6584	7243
ALL01_642_8	6.42	8	6584	7218
ALL01_423_6	4.23	6	6584	7008
ALL01_423_7	4.23	7	6584	6982
Final 2007 CR	4.23	8	6584	6960

Readers may note the final row of the table corresponds with the decision value for the calendar year 2007.

As decided following consultation in 2007, non-interconnector units are not assigned the target FOP, rather they are assigned an index based on their historical performance (this is typically less than 1% FOP).

2009

TABLE 8
CAPACITY REQUIREMENT SENSITIVITIES 2009

Study	FOP % (non-IC)	Adequacy Criterion (LOLE hrs / year)	Peak Market Load (MW)	Capacity Requirement (MW)
1	5.34	8	6920	7490
2	4.23	8	6920	7356

The iterative CREEP process

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)[6] for 2009 that arises from the conventional market capacity, employed to meet the 2009 load trace with wind output netted from this trace

2. Assuming this LOLE is below the target of 8 hours[7], 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 (label 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 (label this BLOAD2)

8. Divide the Capacity of the Reference plant by BLOAD2. This represents the ratio of imperfect-to-perfect plant

[6] This is measured as total expected hours of lost load for the calendar year
[7] This is indeed the case for the 2007, 2008 and 2009 calculations

9. Multiply the ratio in step 8 by the original perfect surplus in step 4 (BLOAD). 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