Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant for the Calendar Year 2009

Consultation Paper

4 July 2008

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I. INDEX

II. INTRODUCTION

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

- A quantity (the Capacity Requirement), determined as the amount of capacity required to just meet an all-island generation security standard; and
- A price determined as the fixed cost of a best new entrant (BNE) peaking plant.

The methodology for the determination of the fixed costs of a BNE peaking plant was set out by the Northern Ireland Authority for Utility Regulation (NIAUR) and the Commission for Energy Regulation (CER), together the Regulatory Authorities, in two decision papers published on the All-Island Project website in 2007[1][2]. These decision papers also set out the fixed costs of the BNE peaking plant as determined for the calendar year 2007. Subsequently the Regulatory Authorities reviewed these costs in relation to the determination of the value of the Annual Capacity Payment Sum for the calendar year 2008. The resulting figure was published on the All-Island Project website by the Regulatory Authorities on 3 September 2007 in a document titled "Annual Capacity Payment Sum: Final value for 2008".

In order to establish the value of the Annual Capacity Payment Sum for the calendar year 2009, the SEM Committee (SEMC) - for both Regulatory Authorities - has conducted a review of the technology options for the BNE peaking plant and have applied the methodology as set out in the decision documents referred to above. This Consultation Paper sets out the options for the BNE peaking plant for 2009 and proposes a technology option. The paper

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

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

then explores the fixed costs associated with the proposed technology option and sets out the proposed resultant value in €/kW. Comments are invited on the proposed selection of technology option and other matters associated with the derivation of the fixed costs of the BNE peaking plant.

The structure of this document is as follows:

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

Section III sets out the background to the development of the CPM and the consultation paper;

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

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

Section VI presents the investment cost estimates;

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

Section VIII presents the inframarginal rent and Ancillary Service revenues calculations for the chosen BNE technology;

Section IX summarises the proposed BNE peaking plant fixed cost;

Section X considers some of the issues raised by respondents to the consultation last year and subsequently regarding the potential for volatility in the BNE price from year to year as a result of the annual re-evaluation, as well as considering the volatility of the Weighted Average Cost of Capital (WACC) parameter;

Section XI provides an indicative value for the Annual Capacity Payment Sum for 2009 based on the proposals in this document and the initial value of the Capacity Requirement determined by the SEM Committee (SEMC); and

Section XII invites comments and views.

Views are invited on any of the issues raised in this Consultation Paper. These are requested by **4pm on Friday the 1st of August 2008** and should be sent to colin.broomfield@niaur.gov.uk and tadhg.obriain@niaur.gov.uk. The SEMC intends to publish all comments received. Those respondents who would like certain sections of their responses to remain confidential should submit the relevant sections in an appendix marked confidential together with an explanation as to why the section should be treated as confidential.

III. BACKGROUND

The principle features of the CPM were set out by the Regulatory Authorities in the High Level Design Principles of the Single Electricity Market (SEM) Capacity Payment Mechanism (CPM). These features were developed into detailed rules through a series of consultation and decision papers published in 2006 and 2007[3].

The Regulatory Authorities decided that for the purposes of determining the value of the Annual Capacity Payment Sum, the cost of new entrant generation should be assessed in terms of a 'Best New Entrant' (BNE) peaking plant. The figure calculated would be expressed in €/kW per year (as an annualised payment) and multiplied by the Capacity Requirement. The Regulatory Authorities further determined that the methodology for assessing the annual fixed costs of the BNE peaking plant should be based upon the approach then employed in the Republic of Ireland (RoI) for determining the costs of a BNE *baseload* plant for the purposes of determining Top-Up and Spill prices for the operational market that existed at the time. The Regulatory Authorities also determined that the resulting cost should be adjusted to account for the infra-marginal rent the BNE peaking plant may derive through its sale of energy into the pool, as well as the estimated revenues the plant may derive through its operation in the Ancillary Services markets. The infra-marginal rent was to be determined through a series of Plexos market model runs, configured with the most up-to-date data from the Market Modelling workstream. The Ancillary Services revenues were to be determined by reference to the prevailing Ancillary Service arrangements in the jurisdiction in which the BNE peaking plant was determined to be located (and in themselves form part of the decision on where the BNE peaking plant should be located).

3 These papers can be found on the All-Island Project website at www.allislandproject.org under the "Design" link at the top of the Home page.

IV. TECHNOLOGY OPTIONS

Introduction

The SEMC has reviewed the options for the choice of technology for the BNE peaking plant. The selection of technology options has been based against the criteria employed in the selection of the BNE peaking plant for 2007 (which was also applied in 2008) as set out in Appendix 1 in the Consultation Paper “Fixed Cost of a New Entrant Peaking Plant for the Capacity Payment Mechanism: Consultation Paper”[4]. This review has been supplemented with discussions with the System Operators (SOs - SONI and Eirgrid) regarding appropriate requirements for a peaking plant in the SEM.

The criteria identified by the SEMC include:

- Grid Code compliance;
- Appropriate set size;
- Accessibility to the Grid;
- Appropriate dynamics;
- Plant Track Record;
- Integrated Pollution Prevention Control (IPPC); and
- Large Combustion Plant Directive (LCPD).

The Consultation Paper further notes that the choice of peaking plant technology should be decided on the basis of least-cost, calculated in terms of €/kW per year and that the characteristics of a peaking plant should conform to the requirements of peaking operation, i.e. a plant which is reliable and flexible to operate. The peaking plant chosen for the CPM should be commercially available and appropriate, both in terms of fuel type and technology, to the existing All-Island electricity system.

In determining the appropriate technology for the BNE peaking plant for 2007 (identified as an open-cycle gas turbine), the SEMC noted that alternative technologies could be considered but that these tend to be more expensive when operated in peaking mode, for example:

[4] AIP/SEM/124/06, September 2006

- Combined-cycle gas turbine and conventional thermal plant tend to be more suited, technically and economically, to 'baseload' and 'mid-merit' modes of operation. Although cycle efficiencies are good (total electrical efficiency approximates to 52% to 60%) the start-up times from cold are long: about 4 hours for combined-cycle gas turbines and up to 8-12 hours for conventional thermal plant. In combination with long shut-down periods, and notwithstanding limitations on flexibility, this makes the cost of each start-up / shut-down very expensive compared with other technologies.

- Reciprocating engines used in peaking applications are typically of the medium-speed diesel type. Medium-speed diesel engines are available up to 10MWe and slow speed diesels up to around 30MWe. High speed diesels are rarely found in unit sizes of greater than 1MW – a size much smaller than that which either System Operator would find helpful as a peaking plant. Electrical efficiencies of these plant are between 38% and 42% and they have an advantage compared to open cycle gas turbines when it comes to part load operation. However, as will be seen later, 30MW is somewhat small for a peaking plant for the SEM.

- Pumped storage hydroelectric plant can, in some instances, be more economically attractive than open-cycle gas turbine plant for peaking applications. However, the capital cost is very sensitive to the nuances of a particular scheme and, more importantly, there must be a suitable site to exploit in the first instance.

The SEMC do not consider that the fundamental features of these alternative technologies have changed and therefore, since no suitable alternative new technology option has arisen, consider that an open-cycle gas turbine remains the most appropriate technology for the provision of peaking capability owing to its relatively low capital cost and operating flexibility.

As noted in the aforementioned Consultation Paper, gas turbines generally fall into one of three main categories:

i) Heavy-duty industrial gas turbines, also called E-Type (derived from GE, type E) which are considered 'conventional in design': The firing temperatures and cycle efficiency of these units are conservative by modern standards and this is reflected in the design and choice of materials throughout the unit. These units range in output from 15 to 180 MW and yield an open-cycle efficiency of approximately 29 to 34%.

ii) Advanced heavy-duty industrial gas turbines, also called F-Type (from the GE type F) and the very advanced H-Type: The firing temperatures, compression ratios, combustion systems, cooling and sealing systems, material selection, manufacturing processes and blading designs in the case of these machines are considered in many cases to be 'state of the art'. In general, these units fall into two main output bands in simple cycle, 50 Hz configuration: 60 to 100 MW and 250 to 310 MW. The open-cycle efficiency figures range from about 33% to 39% per cent. These plant tend to have lower reliability (higher forced outages) and availability (higher scheduled outages) compared to the conventional heavy duty machines. Also they tend to be less flexible in operation due to longer start times and slower ramp rates and are more suited to combined cycle configurations and baseload operation.

iii) Aero-derivative gas turbines: These gas turbines, as the term suggests, are land-based derivatives of successful aero-engine designs. Aero-derivative units are characterised by high electrical efficiency figures and short start-up times. The largest aero-derivative gas turbines are in the region of 40 to 58 MW, going down to 2 to 3 MW at the low end of the range. Typically, open cycle efficiencies of aero-derivative units, in the 25 to 50 MW output band, are in the range 39 to 42%.

Technology Selection

There is a vast spectrum of gas turbine engines available from a variety of manufacturers: each a different size with bespoke performance characteristics. A range of engines have been identified as possible candidates for the BNE peaking plant for 2009. These engines have been reviewed against the criteria applied in 2007 as outlined in the following sections.

Size

In the range 40-180 MW the following open-cycle gas turbines have been identified:

TABLE 1
TECHNOLOGY OPTIONS FOR THE 'BEST NEW ENTRANT'
PEAKING PLANT FOR 2009

Unit Name	Capacity	Efficiency	Base Case Fixed Cost per yr[5]
GE LM6000 PD Liquid Fuel	40 MW	40.4%	-
GE LM6000 PD Sprint	47 MW	41.2%	-
Rolls Royce Trent 60DLE	52 MW	42.0%	105.66
Rolls Royce Trent 60WLE	58 MW	40.0%	-
Pratt & Whitney FT8 SwiftPac 60	61 MW	37%	-
GE6FA	76 MW	35.5%	-
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

Discussions with the SOs suggest that a peaker for the All-island system should be no less than 50MW in capacity to be of value to the system and, in relation to the Republic of Ireland, a unit of at minimum around 70 to 90MW would be preferred. Factors included in considering this size include the increasing depth of wind power penetration and the size of existing conventional plant on the system. Taking the minimum criteria of 50MW neither of the LM6000s seem suitable and the remaining aero engines should also be ruled out. However an investor may choose to meet the SO preferred size by siting two units at the

5 Base Case unit costs have been used for evaluation throughout this report. A market adjusted cost is presented and discussed in Section V. The base case unit costs have been evaluated for those units not ruled out by other criteria and using the data described later in the paper scaled appropriately for the size of the unit (for example the land costs associated with an aero engine are much less than those required for the large heavy duty units). The values shown relate to the Republic of Ireland only for ease of illustration but similar relative differences exist for Northern Ireland too.

same location, and therefore the possibility of the BNE peaking plant being two units has been considered by the SEMC.

Start-Up and Dynamics

Peaking duty requires a plant which is reliable and flexible to operate. In particular, it suits a generation technology with short start-up and shut-down times.

All but one of the gas turbines listed above are capable of achieving full output within about 20 minutes (or less) from notification to start. The exception is the GE 6FA which requires a sustained period (30 minutes) at limited output to allow for thermal expansion. The SEMC therefore consider that the GE6FA should be discounted since it fails to meet the 20 minute start-up criteria for Replacement Reserve.

Proven Track Record

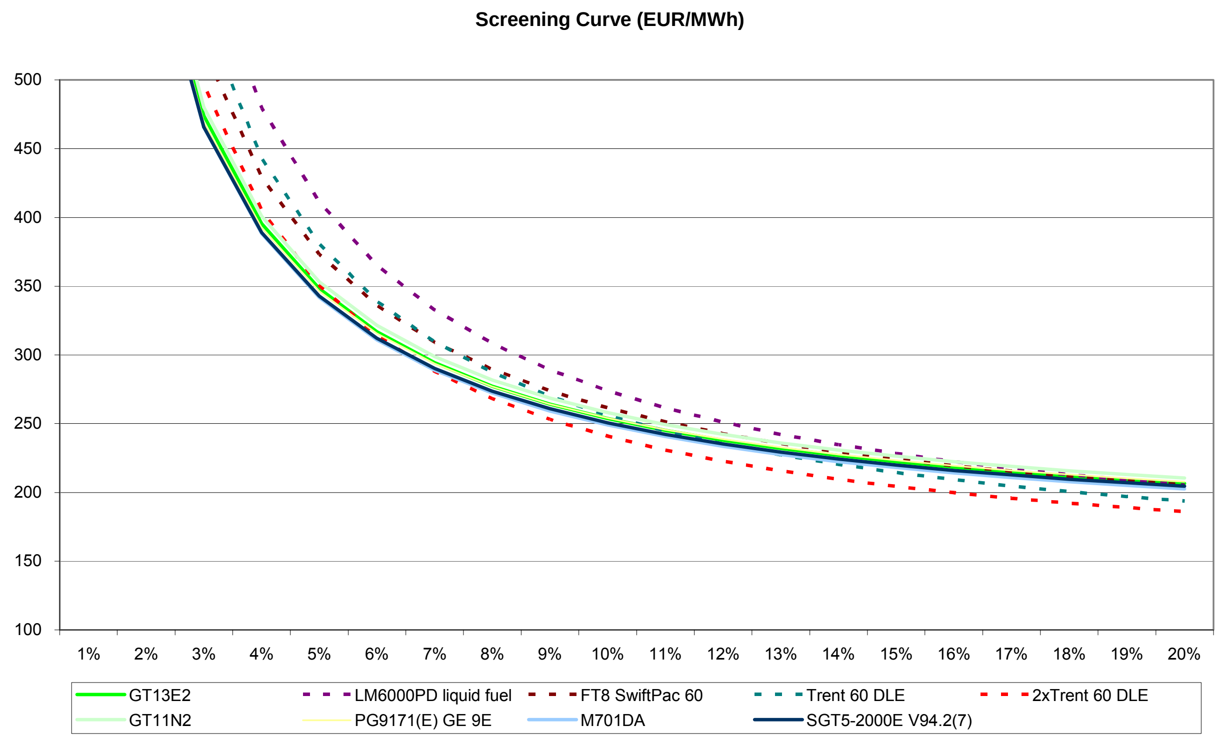
The peaking plant chosen for the CPM should be commercially available and appropriate, both in terms of fuel type and technology, to the existing All-Island electricity system.

The Rolls Royce Trent 60WLE does not have a lengthy track record and therefore the SEMC considers its limited operational experience makes it an unsuitable choice for the best new entrant peaking plant at the present time. The remaining turbines all have considerable track records:- Of the aero engines there are approximately 600 of the LM 6000PD liquid fuel units in operation, approximately half of which are as peaking plant, while there are 75 of the gas fired versions in operation; 300 of the Pratt & Whitney SwiftPac units are installed with over 2 million operation hours; and there are 21 Trent 60 DLE units running. For the heavy duty turbines there are 61 GE 6FAs with over 850,000 operating hours; the Alstom GT11N2 is operating in 37 countries; the GE 9E is a workhorse with 430 units installed and over 18 million operating hours; and there are 120 of the Siemens units in operation.

Cost

The graph below provides a comparison of the total costs of generation for each of the candidate gas turbines (having excluded the ones noted above).

FIGURE 1
BASE COST SCREENING CURVE ANALYSIS FOR THE 'BEST NEW ENTRANT' PEAKING PLANT FOR 2009



From the above curve the two LM6000s are the worst performers with the SwiftPac coming in a close third and therefore the SEMC considers that these machines should be ruled at this stage. At the other end of the scale the Siemens SGT5-2000E is the best performer with the Mitsubishi M701DA coming in a close second at the low end of utilisation.

Taking the above into account leaves a single aero engine (the Trent 60DLE) and four of the original five heavy duty units. As noted above if the minimum capacity requirement suggested for the Republic of Ireland were to be considered the final aero engine would also be discounted, however as noted earlier, the SEMC has considered the possibility of two units being considered as the BNE peaking plant. Thus the SEMC have considered the Trent 60DLE for the purposes of evaluating as a two unit configuration to meet the size requirements given that it meets the criteria for a peaking plant. If the BNE peaking plant were to be a two unit facility then the values in the above table for the Trent 60 DLE would need to be changed to:

TABLE 2
REVISED BASE DATA FOR THE ROLLS ROYCE TRENT 60DLE BASED ON 2 UNITS AT A SINGLE SITE

Unit Name	Capacity	Efficiency	Base Case Fixed Cost per yr
Rolls Royce Trent 60DLE	2 x 52 MW	42.0%	94.47

To complete the analysis, the fixed cost per kW per annum has been evaluated for this configuration to allow for comparison with the larger, heavy duty units. Double units such as this have not been considered for the other aero engines since they have been ruled out of contention for the BNE peaking unit for other reasons (cost from the screening curve analysis and track record in the case of the Trent 60WLE). The above table shows, when compared to the earlier table, that although doubling the size of the Trent 60DLE peaking station does reduce the unit fixed cost per annum, it is still considerably higher than the remaining heavy duty units, however as can also be seen from the screening curve, this configuration does have a lower overall cost at higher running regimes due its much better cycle efficiency than the other units[6]. The SEMC does not expect the BNE peaking unit will operate significantly in the energy market (see Section VIII) and thus the high cycle efficiency would not seem to compensate for the additional per unit fixed cost. At this stage therefore the double Trent configuration has been ruled out.

An analysis of the costs (in terms of €/kW/yr) for each of the remaining units shows that the additional investment required for some of the larger units does not lead to significant savings in the per unit fixed cost per annum – it would be expected that as the size of the unit increases economies of scale would lead to improvements in the per unit cost. The table shows that both the Mitsubishi and the Alstom 13E2 show increases in the unit fixed cost per annum despite the considerably additional size of the units. An investor would logically be seeking to obtain a lower unit cost in return for the additional investment in the extra capacity.

The remaining units – the Siemens SGT5 2000E, the GE9E and the Alstom GT11N2 – meet all of the criteria and show a decrease in unit cost as the size of the unit increases. The Siemens is the cheapest in terms of per unit fixed cost

6 Note that the analysis has been performed using RoI fuel costs. If UK fuel costs were to be used the cross-over point would occur at a higher utilization – nearer to 9%.

per annum and also in terms of full costs from the screening curve analysis. It also has a slightly higher efficiency level than the other units which would suggest it to be the optimum plant for the BNE peaking plant for 2009. Least per unit cost is one of the criteria employed in determining the BNE peaking plant as, given the existence of an explicit Capacity Payments Mechanism, a rational investor in peaking technology will generally be incentivised toward units with lower per-kW fixed costs at the expense of higher gross investment cost (and hence risk). This would be the case where a strong set of comparable choices exist, such as the remaining heavy-duty units. Given this, the SEMC considers that the BNE peaking plant for 2009 should be the Siemens SGT5 2000E.

Having identified a technology choice a number of further technology related matters need to be considered. These are set out in the following subsections.

Efficiency Degradation

For the selected OCGT plant, the SEMC have considered the impact of inlet/outlet losses and the lifetime degradation of the unit over 15 years (see later). For the inlet a 4 inch water gauge pressure drop has been assumed which gives 4 x 0.5% (i.e. 2%) reduction in power. A similar assumption has been made for the outlet which gives 4 x 0.15% (0.6%) reduction. The aging will affect the output by approximately 5% after 15 years (based on distillate firing – see below). This gives an average degradation of around 3%. Taken together the SEMC considers a reasonable lifetime net plant output for the selected BNE peaking plant to be 159MW.

Planned Outage Duration

The SEMC considers the estimated annual planned outages for maintenance for this type of technology and configuration for peaking operation employed in 2007 to remain a reasonable estimate. This figure was set at 13 days and the SEMC proposes to continue to use this figure for 2009.

Forced Outage Rate

The Regulatory Authorities used a figure of 2% for the Forced Outage Rate for the BNE peaking plant in 2007. This was considered an appropriate mature value. The SEMC considers this to remain a reasonable for value and propose to adopt it for 2009.

Fuel Choice

In 2007 the Regulatory Authorities determined that the BNE peaking plant would run on distillate only. This decision was largely due to the costs associated with booking gas capacity in advance to enable the plant to run if required. In making this decision the Regulatory Authorities sought views from interested parties regarding the liquidity of secondary gas trading so as to assess the feasibility of trading out such charges, or perhaps purchasing gas on a short term basis.

Since then a change to the arrangements in the Republic of Ireland has been implemented to shorten the gate closure for the trading of daily gas capacity. No such change has been made in relation to Northern Ireland. Gate closure in the Republic of Ireland for such trades is now 01:00 hours on the day to which the trade relates. While this is an improvement on the situation the SEMC has yet to see evidence of liquidity in secondary gas trading.

The SEMC wishes to invite views from respondents on the tradability of gas capacity in both Northern Ireland and the Republic of Ireland. However at this stage the SEMC considers that the BNE peaking plant will likely be fired on distillate only given the perceived lack of liquidity in the trading of gas capacity.

A further consideration is whether additional equipment is required to enable a distillate running plant to comply with emissions limits. Last year it was concluded that Selective Catalytic Reduction (SCR) equipment was required to ensure compliance. This requirement has again been reviewed for this year's evaluation. The NOx emission limits for liquid fuels like distillate are 120 mg/Nm3 and running hours bare less than 500 hours in a year gas turbines are excluded from these limit values. The Siemens 2000E when operating at full load emits 25 ppm or 50 mg/Nm3 which is well inside the limit. At part load the emissions will be higher but the SEMC does not consider it likely that they will reach the 120 mg/m3 limit. Consequently the SEMC does not consider it necessary for the BNE to include an expenditure for SCR equipment.

It is for consideration whether a rational investor may decide to invest in such equipment given the likelihood that emissions limits are only likely to ever be reduced and, consequently, by investing at the construction of the plant the investor could avoid an outage (and additional cost) to install such equipment at a later stage in the operation of the plant. However at this stage the SEMC does not consider the case for such investment to be sufficiently compelling for an investor to make such a decision.

V. ECONOMIC AND FINANCIAL PARAMETERS

Pricing

All cost estimates used in the analysis presented in this review are in real values based on price levels for a plant commencing commercial operations at the end of 2008.

Cost of Capital

The rate of return earned by a new entrant must be sufficient to cover all finance costs and all risks of entering the market. Given the sensitivity of the final price to this element the SEMC has set out below in detail the approach employed to determine the appropriate level of Weighted Average Cost of Capital (WACC) for the BNE peaking plant.

A reassessment of the WACC has been carried out in order to update the value for discounting the costs to the present. The basis for this reassessment was

- to determine the WACC for an international investor (the energy market is international); and
- to determine the WACC over a long time, compatible with the long run horizon for investing in generation capacity.

WACC Elements

The WACC consists of the cost of debt, cost of equity and the gearing. The following variables have to be determined:

1. nominal risk free rate;
2. inflation;
3. debt spread
4. equity market premium;
5. asset beta;
6. tax rate; and
7. gearing.

The following addresses each of these variables in turn. The nominal risk free rate, inflation forecast, debt spread and tax rate are fixed as of May 16, 2008.

The SEMC proposes to fix definitive values for these parameters ahead of publication of the Decision document for the 2009 BNE peaking plant.

1. Nominal Risk Free Rate 4.58% (Ireland) / 4.82% (UK)

The nominal risk free rate in the EU equals the yield on Euro AAA-rated government bonds. The yield (spot rate) for a 15 year period is currently 4.58%.[7] For the UK, the yield on the 15 year Gilt is currently 4.82%.[8]

TABLE 3
NOMINAL RISK FREE RATE

Reference	Republic of Ireland	Northern Ireland
This consultation	4.58%	4.82%
2007 decision	5.53%	5.53%

2. Inflation 2.40% (Ireland) / 2.40% (UK)

The SEMC has considered two methods for determining the long-term inflation forecast. The first method is the inflation forecast reported by the central banks, the second method is the market expectation reflected in inflation-indexed government bond markets.

Under the first method, the Bank of England reports a 2.40% mid-point inflation forecast. The European Central Bank reports a 2.40% inflation forecast, 0.40% above its current target inflation rate.

Under the second method the market forecast of the long-term inflation (10 year) is determined by subtracting the yield on inflation protected government bonds from the yield on (ordinary) government bonds. The French and UK government issues such inflation protected notes, known as OAT €I (2015) and Index Linked Treasury Stock (2016). For Euro investments, the yield on French inflation

7 Source : European Central Bank : http://www.ecb.int/stats/money/yc/html/index.en.html.
8 Source UK: http://www.bankofengland.co.uk. Values taken from:

IUDLNPY	Title: Yield from British Government Securities, 20 year Nominal Par Yield
IUDMNPY	Title: Yield from British Government Securities, 10 year Nominal Par Yield

protected notes is 1.65%. Compared to the yield on the similar non-protected French notes, the inflation forecast for the Euro area is currently 2.40%.[9]

Under the same method for the UK the yield on the 2016 inflation protected government bonds is currently 1.24%. This means that the inflation forecast under this method is currently 4.84 -/- 1.24% = 3.60%.[10]

The SEMC considers the central bank's forecast as more reliable, especially since the UK index-linked Gilt is considered in over-demand.

3. Debt Spread 2.25% (Ireland) / 2.25% (UK)

In light of the changed conditions for borrowing money at a BBB-rating, the SEMC has been advised to adjust the debt spread over government bonds from 2.00% used for 2007/8 to 2.25% for 2009.

4. Equity Risk Premium 5.50% (Ireland and UK)

Last year this was estimated at 5.50% - an arithmetic average of the observed equity risk premia.

The most quoted source for equity risk premia is the data presented by Dimson, Marsh and Staunton (2007). The equity risk premium is estimated as 5.40% for the UK arithmetically and 4.20% geometrically, with the equivalent values for the Republic of Ireland being lower than these.

In light of past decisions by the Regulatory Authorities on the equity risk premium, which generally range from 5.00% to 6.00%, The SEMC proposes to maintain the equity risk premium at 5.50%. However, the SEMC wishes to invite views as to the appropriateness of following more recent precedents, such as that set by the Competition Commission, which recently quoted a range of 2.5% to 4.5% in its recent decision regarding Heathrow and Gatwick airports[11].

5. Asset Beta 0.60 (Ireland and UK)

The asset beta is an important parameter, as it compares the volatility (risk) of the returns from a BNE peaker to the returns from the global equity market.[12]

9 Source: http://www.aft.gouv.fr/article_778.html?id_article=778

10 Source: http://www.bankofengland.co.uk/mfsd/iadb/fromshowcolumns.asp?Travel=NIxSCx&ShadowPage=1&SearchText=index+linked+yield&SearchExclude=&SearchTextFields=TC&Thes=&SearchType=&Cats=&ActualResNumPerPage=&TotalNumResults=14&C=KQ&ShowData.x=38&ShowData.y=11

11 http://www.competition-commission.org.uk/inquiries/ref2007/heathrow/index.htm

12 The market risk is captured in the market risk premium

This asset beta captures the business risk, but does not capture the financial risk associated with the project (BNE-peaker).[13]

Last year, the asset beta was not separately determined, but implicitly it was

$\beta_a = \beta_e / (1 + (1\text{-}T)*D/E) = 1.83 / (1 + (1\text{-}0{,}125) * 70/30) = 0.60.$

The SEMC considers that an asset beta of 0.60 is in line with international[14] estimates of the asset beta, which generally range from 0.50 to 0.80 for generators.

6. Tax Rate — *12.5% (Ireland) / 28% (UK)*

The applicable tax rate is the marginal corporate tax rate that an investor has to pay over the project's returns. Energy market regulators across the world consistently use the marginal corporate tax rate of the project, rather than the personal income tax rate. The marginal corporate tax in the Republic of Ireland is currently 12.5% and in UK 28%.

7. Gearing (Debt / Total Assets) — *70% (Ireland and UK)*

Gearing is the company's ratio of total debt to total assets. Usually, a company finances its projects with the same gearing as its current operations. The SEMC considers that a 70% gearing is achievable for generating companies and projects alike. The following provides examples in relation to generating companies

ESB	2006:	62%[15]
Viridian	2007:	80% / 2006 : 81%[16]
AESCorp	2006:	81%[17]

13 The financial risk will be captured by calculating the equity-beta, by combining the asset-beta, tax rate, and gearing in the following formula: $\beta_e = \beta_a * (1 + (1\text{-}T) * D/E)$. Business risk and financial risk together determine the volatility of the equity returns.

14 The Regulatory Authorities do not consider the asset beta to differ between countries. The equity beta does differ between countries, since the equity beta captures not only business risk, but also the finance risk adjusted for tax.

15 http://www.esb.ie/main/about_esb/annual_report_2006.jsp

16 http://www.viridiangroup.co.uk/Investor/AnnualReports.asp

17 http://investor.aes.com/phoenix.zhtml?c=76149&p=irol-irhome

Resulting WACC

The pre-tax WACC is then calculated as follows for investments in peak-generation in the Republic of Ireland and Northern Ireland, real:

WACC = $(r_d * g) + [r_e * (1-g)] / (1 - t)$

Where:
r_d = Cost of Debt = (Risk-Free Rate + Debt premium);
r_e = Cost of Equity = ($r_f + \beta$ * Equity Risk Premium);
r_f = Nominal Risk - Free Rate;
β = Beta;
g = Gearing;
t = Tax Rate.

TABLE 4
WEIGHTED AVERAGE COST OF CAPITAL CALCULATION FOR THE 'BEST NEW ENTRANT' PEAKING PLANT FOR 2009

VARIABLE	LAST YEAR		THIS YEAR	
	RoI	UK	RoI	UK
Nominal Risk Free Rate	5.53%	5.53%	4.58%	4.82%
Inflation	2.60%	2.60%	2.40%	2.40%
Real Risk Free Rate	2.86%	2.86%	2.13%	2.36%
Debt Risk Premium	2.00%	2.00%	2.25%	2.25%
Real Cost of Debt	**4.86%**	**4.86%**	**4.38%**	**4.61%**
Real Risk Free Rate	2.86%	2.86%	2.13%	2.36%
Market Rate of Return	8.36%	8.36%	7.63%	7.86%
Tax Rate	12.50%	30.00%	12.50%	28.00%
Asset Beta	0.60	0.60	0.60	0.60
Equity Beta	1.83	1.59	1.83	1.61
Cost of Equity	**12.93%**	**11.58%**	**12.17%**	**11.21%**
Debt %	70.0%	70.0%	70.0%	70.0%
Equity %	30.0%	30.0%	30.0%	30.0%
WACC, real Pre Tax	***7.83%***	***8.36%***	***7.24%***	***7.90%***

The SEMC considers a pre-tax WACC figure of 7.24% should be used for evaluating the BNE peaking plant if sited in the Republic of Ireland and 7.90% if sited in Northern Ireland.

Plant Life

The 2007 and 2008 BNE price was based on a plant life of 15 years. The SEMC propose to use the same period for 2009 as this represents a fair assessment of the lifetime of a plant from an investor's perspective.

Currency

All prices are expressed in Euros.

VI. INVESTMENT COST ESTIMATE

This section sets out the proposed investment costs used in the determination of the annualised fixed costs of the BNE peaking plant. In turn these costs are based on the proposed technology of the Siemens SGT5 2000E.

Base Case Investment Costs

Investment costs can be subdivided between:

- Site Procurement costs;
- Pre-Financial close costs; and
- Post-Financial close costs.

The estimated cost of each of these is discussed in the subsections below.

Site Procurement

In considering the optimum location for the BNE peaking plant on an all-island basis the approach taken has been to examine the matters which an investor would consider in deciding where to locate a plant. This would include all costs associated with the delivery of the facility and the on-going operational costs. Thus the SEMC has reviewed a number of different costs including locational transmission charging and site availability. The SEMC has identified several possible locations from information from SOs and have evaluated sites in both Northern Ireland and the Republic of Ireland. To aid transparency the SEMC has in this year's consultation provided information pertaining to both jurisdictions so as to provide respondents with the opportunity of understanding more clearly the differences applicable in each jurisdiction. The key differences between the jurisdictions lie in the different Tax rates that apply, the land purchase costs (dealt with in this section), Rates and Transmission charges (see subsequent sections). In this way respondents can compare the information provided for the two jurisdictions and provide comments accordingly. In general the best location in Northern Ireland is in Belfast while in the Republic of Ireland the best locations are in the West and South East.

The estimated cost of the land required to accommodate the plant (4,800 m2) together with the necessary site preparation cost is €2.244 million in Northern Ireland and €1.343 million in the Republic of Ireland.

Pre-Financial Close Costs

These costs include engineering costs, legal, finance, consultancy and the cost of an environmental impact assessment. It also includes manpower costs up to and including contract award. The estimate for pre-financial close costs amount to a total of €2.084 million.

Post-financial Close Costs

The post-financial close costs consist largely of the Engineering, Procurement and Construction (EPC) contract costs, but there are a number of other costs incorporated into this heading too. Further detail on all of these are provided below.

EPC Contract

The estimated cost of the EPC contract is based on the plant configuration discussed above. The cost items and technical data were sourced from a combination of publicly available catalogues direct communications with vendors and the know-how and experiences of our consultants from similar projects on the techno economic aspects of power plants assets. This included use of their data base on items such as civil works, electric equipment, transportation, construction and erection costs and commissioning. The EPC contract is considered to include the costs of the gas turbine plant (gas turbine, starting and lube oil system, fuel forwarding system), the electric generator, the balance of plant (air intake filter, silencer, plant control system, acoustic enclosure, fire protection), the dry low NOx combustion system and fast start devices and dual fuel capabilities for the heavy duty gas turbines. Also in the EPC contract are included: civil, mechanical, electrical and Instrument & Control works, cabling, commissioning, training and spare parts. Note that the cost of spare parts is fully included in this cost rather than being split into “Other Costs” as was done last year. The estimated cost of the EPC contract, including contingency, for an open cycle plant with this configuration is €59.531 million.

Interconnection to Electrical Transmission System

On the basis of the size of the BNE peaking plant it is assumed connection would be at 110 kV.

The assumptions made with respect to the costs associated with the electrical connection are:

- The BNE operator shall be responsible for the capital cost of a shallow connection between the plant and the grid;

- Switchyard at step up HV terminal, a 2 km single circuit (110 kV) and extension of an existing AIS station will connect the power station to the grid; and
- The generator breaker, bus duct and step-up generator transformer is included in the EPC contract as part of the BNE plant.

The capital cost estimate for the grid connection, based on a 110 kV single circuit line, 2 km in length, as discussed above is €2.550 million.

Distillate Facilities Costs

Since the BNE is proposed to run on distillate only, costs associated with storage facilities are incurred. These are estimated at €906,000.

Other costs

These costs include manpower during construction, taxes and insurance during construction, purchased electricity and fuel during construction, Accession and Participation Fees when joining the Trading and Settlement Code and contingencies. Estimates are based on historical data, the requirements of the Trading and Settlement Code and experience. The total for these costs is estimated as €2.897 million in Northern Ireland and €2.723 million in the Republic of Ireland (the main difference being down to the differences in the Tax regimes).

In addition to the above the interest during construction needs to be added. Interest during construction is an expense that is part of the investment cash flow, because the annualization of the investment costs with the pre-tax WACC do not account for interest during construction.

The interest during construction has been calculated as €2.328 million for the Republic of Ireland (7.24% pre-tax WACC) and €2.576 million for Northern Ireland (7.90% pre-tax WACC) based on a disbursement schedule of 90% in the year preceding commissioning and 10% in the year of commissioning.

Total Investment Cost

Based on the above Table 5 and Table 6 below show the estimated investment cost estimate for the BNE peaking plant in Northern Ireland and the Republic of Ireland.

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

<u>Site Procurement</u>	**2,244**
<u>Pre Financial Close Costs</u>	
Owner's manpower costs up to contract award	893
Financial, legal costs, engineering, consultancy and EIA	1,191
Total Pre-Financial Close Costs	**2,084**
<u>Post Financial Close Costs</u>	
E.P.C. Contract (including contingency)	59,531
Electrical Interconnection	2,550
Distillate Facilities	906
E.P.C Total	**62,987**
<u>Other costs</u>	
Owners manpower during construction	1,191
Taxes, insurance during construction	417
Purchased electricity, fuel during construction	298
T&SC Fees	6
Contingencies	985
Interest during construction	2,576
Total Other costs	**5,473**
<u>TOTAL INVESTMENT COST</u>	**72,788**

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

<u>Site Procurement</u>	**1,343**
<u>Pre Financial Close Costs</u>	
Owner's manpower costs up to contract award	893
Financial, legal costs, engineering, consultancy and EIA	1,191
Total Pre-Financial Close Costs	**2,084**
<u>Post Financial Close Costs</u>	
E.P.C. Contract (including contingency)	59,531
Electrical Interconnection	2,550
Distillate Facilities	906
E.P.C Total	**62,987**
<u>Other costs</u>	

Owners manpower during construction	1,191
Taxes, insurance during construction	298
Purchased electricity, fuel during construction	298
T&SC Fees	6
Contingencies	930
Interest during construction	2,328
Total Other costs	**5,051**
TOTAL INVESTMENT COST	**71,465**

Market Adjustment

The current market for procuring industrial gas turbines is volatile and there is a significant degree of subjectivity in estimating the required investment costs. Given this subjectivity and volatility the SEMC obtained cost estimates from a number of reputable sources. In choosing the best cost estimate it is the opinion of the committee that the mid-point value of the range received should be used. This gives an adjusted investment cost 18% greater than the base case estimate, which is detailed above.

RECURRING COST ESTIMATE

This section considers those costs which are incurred annually by the BNE peaking plant.

Operation and Maintenance

This heading considers matters typically addressed through a Long Term Service Agreement and also includes owner's salaries. The estimated cost of these items is €1.176 million per annum.

Insurance and Miscellaneous

Insurance, property tax and other miscellaneous costs are estimated to be €1.008 million per annum. The insurance value has been selected to reflect changes in the risk profile of power plants as observed by global insurance markets.

Rates

As with site procurement, Rates have been estimated for both Northern Ireland and the Republic of Ireland. The estimated cost of Rates in Northern Ireland is €0.578 million per annum while in the Republic of Ireland Rates are estimated as €1.315 million per annum.

Transmission and Market Operator Charges

Generation is subject to a fixed charge for SEMO of €116/MW which equates to approximately €19,000 for the BNE peaking plant. Generation users pay Locational Use of System charges if located in the Republic of Ireland depending on the relative costs imposed on the system while currently in Northern Ireland the charges are postalised. Work is currently progressing to harmonise the charging methodology from October 2008 however at this stage the outcome of this review has yet to be determined. Given this the SEMC proposes to utilise the existing tariff numbers for each jurisdiction. However if, by the time the Decision is made regarding the BNE peaking plant for 2009, the charges for Transmission have been confirmed, the SEMC would propose to re-evaluate using the new figures. On this basis for a BNE peaking plant located in Northern Ireland the estimated annual transmission charges are €0.826 million while when located in the Republic of Ireland these are estimated to be €0.916 million.

Fuel Working Capital (Storage)

With an assumption of a distillate fuel price of €13.09/GJ and a storage capacity sufficient for 100 hours full load operation an allowance of €0.168 million for the Republic of Ireland and €0.183 million have been made to reflect the working capital costs of storing fuel on site. The derivation of these costs for the Siemens SGT5-2000E is as follows:

Gross maximum output (MWe)	168
Averaged efficiency	34.1
Fuel cost (€/MWh,th)	47.124
One hour fuel costs (€)	23,216
100 hours fuel costs (€)	2,321,651
Allowance @ 7.24% real, pre tax	€0.168 million for RoI
Allowance @ 7.90% real, pre tax	€0.183 million for NI

VII. INFRAMARGINAL RENT AND ANCILLARY SERVICES REVENUES

The approach to the derivation of the estimated inframarginal rent for the BNE peaker replicates the process used for 2007 and 2008. Revenues for the BNE peaker result from the energy (SMP) market and also from Ancillary Services.

In relation to infra-marginal rent, the most up-to-date SEM Plexos model was procured from the Market Modelling Group, based in CER. This model is identical to that used in the recent Directed Contracts parameter calculations, with some minor adjustments made to facilitate more recent developments in likely changes in generation capacity during the calendar 2009 period. Twenty four full year half-hourly simulations of the SEM in 2009 were run, in which forced outage patterns were randomly generated from one iteration to the next to give a spread of system margin scenarios across the year[18].

It was observed the Siemens 2000E plant was not scheduled in all but one of the twenty four iterations. In the iteration in which the plant was called, the running occurred over a single, 7-period duration. In that duration the plant generated 197.6 MWh of exported energy, earning an infra-marginal rent of just €2,834 in real 2009 SMP terms[19]. When these operating hours and profits are averaged over the twenty four iterations, this yields an average of only 8.2 MWh and €118. These results suggest that it is very unlikely the plant would expect any material profits from the energy market were it participant in the SEM in 2009. For prudence, a value of €118 has been implemented in the final calculation even though its effect on the result is immaterial compared to a simple assumption of zero infra-marginal rent.

For Ancillary Services the SEMC recognises that work is currently underway to seek to harmonise and redefine the arrangements for rewarding the provision of Ancillary Services and that this work has, so far, only been developed to a high level. Given that the precise nature of the resulting arrangements for 2009 cannot be known at this stage and that the general view is that whatever arrangements are finally determined they will not be implemented until mid 2009, the SEMC has employed the existing arrangements for each jurisdiction in estimating the possible Ancillary Services revenue for the BNE peaking plant. The estimates

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

[19] The plant itself is not permitted to influence the pool price in the Plexos model.

are: for Northern Ireland[20] €0.849 million, while for the Republic of Ireland €1.182 million.

[20] This is based on the System Support Services Agreements which include payments other than for Ancillary Services alone and may therefore be an over-estimate at this stage.

VIII. PROPOSED BEST NEW ENTRANT PEAKING PRICE

Based on the analysis presented above the estimated proposed BNE peaking plant fixed costs for 2009 in each of Northern Ireland and the Republic of Ireland (accounting for the differences in Land costs, Rates, Transmission Charges and tax is €81.73/kW/yr in Northern Ireland and €81.24/kW/yr in the Republic of Ireland. These costs are summarised in Tables 7 and 8 below.

TABLE 7
FIXED COST ESTIMATE FOR 'BEST NEW ENTRANT' PEAKING PLANT LOCATED IN THE NORTHERN IRELAND
(€ '000S)

Costs		***BNE 2009***
Capital Cost		
Capex (Base)	€ '000	72,788
Capex (Adjusted)	€ '000	85,889
Plant life	years	15
WACC	% p.a.	7.90%
Fixed Costs		
Operations and Maintenance	€ '000	1,176
Transmission and SEMO charges	€ '000	845
Insurance and Miscellaneous cost	€ '000	1,008
Rates cost	€ '000	578
Fuel Storage	€ '000	183
Annualised Capital plus Fixed Costs	**€/kW**	**86.78**

	€/kW/yr
Unadjusted BNE Cost	77.19
Adjusted BNE Cost	86.78
Energy Market Infra Marginal Rent	(0.0007)
Ancillary Service Revenue	(5.05)
Final BNE Cost	**81.73**

TABLE 8
FIXED COST ESTIMATE FOR 'BEST NEW ENTRANT'
PEAKING PLANT LOCATED IN THE REPUBLIC OF IRELAND
(€ '000S)

Costs		***BNE 2009***
Capital Cost		
Capex (Base)	€ '000	71,465
Capex (Adjusted)	€ '000	84,326
Plant life	years	15
WACC	% p.a.	7.24%
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	168
Annualised Capital plus Fixed Costs	**€/kW**	**88.28**

	€/kW/yr
Unadjusted BNE Cost	79.24
Adjusted BNE Cost	88.28
Energy Market Infra Marginal Rent	(0.0007)
Ancillary Service Revenue	(7.04)
Final BNE Cost	**81.24**

On the basis of the above the SEMC proposes the BNE peaking plant for 2009 to be the **Siemens SGT5 2000E located in the Republic of Ireland at an annualised Fixed Cost of €81.24/kW/yr.**

Note that there is a fine balance between locating in Northern Ireland or the Republic of Ireland.

IX. ADDRESSING VOLATILITY

During the consultation process which led to the finalization of the methodology for determining the fixed costs of the BNE peaking plant, a number of respondents commented that evaluating the BNE price annually, in particular the cost of the gas turbine which constitutes approximately 50% of the EPC costs, could lend volatility to the CPM. Some respondents suggested that the BNE price should somehow be tied to the capacity constructed in a given year.

In response the Regulatory Authorities noted that they recognised the potential for variation of EPC costs on a year on year basis, but that it was the case that investors would be exposed to these variations in an energy-only market and therefore reflecting such variations within the BNE pricing mechanism was, in the Regulatory Authorities opinion, a reasonable approach. The Regulatory Authorities further considered that the application of a smoothing mechanism or, as has been suggested by some respondents, placing limitations on the extent to which the price could vary from year to year could distort the market signals. The Regulatory Authorities further considered that tying the BNE price to capacity constructed within a particular year would create a highly complex mechanism which could be considered as discriminatory, especially in regard to older plant for which such prices would have to be nominated. As a consequence the Regulatory Authorities did not consider such discrimination or complexity to be either reasonable or justified and therefore retained the year on year BNE pricing mechanism.

After further consideration and in response to comments subsequently made to the SEMC outside of the consultation process and since the implementation of the SEM, the SEMC has decided to give further consideration to the potential volatility issue created by the annual evaluation of EPC costs. In this regard two alternatives have been considered:

- Average the EPC prices of several comparable plant to a so called Proxy plant; and
- Average the time series of real historic EPC prices of a selected plant (the identified BNE technology option), adjusting for increased capacity and efficiency.

In considering a proxy plant the SEMC considers that it would only be appropriate to undertake such an approach if the plant over which the “average” was determined were similar, in particular in their MW capacity. An average taken across a series of dis-similar plant would distort the basis upon which it was taken and would not provide a meaningful representation of a BNE peaking plant. Of the possible peaking plant identified for 2009 only the aero derivatives display sufficient similarities to allow a proxy to be determined – the size of the heavy duty turbines differ significantly and therefore cannot be considered for constructing a sensible proxy. However, as identified in the earlier sections all but one of the aero derivatives were ruled out as the BNE peaking plant for 2009 due to lack of track record or by the screening curve analysis. Consequently, at least for 2009, the option of smoothing using a proxy approach has not been pursued further.

To investigate the volatility of the EPC costs the equipment only prices for several aero derivative (GE LM6000, Trent DLE and a proxy 50MW plant) and heavy duty gas turbines (Alstom 11N2 and13E2, GE 6FA and 9E, MHI M701DA and Siemens SGT5-2000E) have been plotted in Figure 2 below. The prices shown in this figure are the yearly equipment only prices in USD/kW from 1999 until 2008 derived from the Gas Turbine World Handbook covering the period from 1999 until 2008. The equipment only price consists of a standard simple cycle plant FOB (free on board – i.e. at the factory and not including transportation costs) including the gas turbine, electric generator and the balance of plant. The prices for the years 2000, 2002, 2005 and 2007 are not available. In the figure averaged price settings have been chosen for these years.

For the Heavy Duty (HD) gas turbines an averaged yearly equipment price has been calculated (refer to the bold lines in Figure 2). Also a linear average in US Dollars, Pounds Sterling and Euro's has been determined (refer to the dotted lines in Figure 2).

In the last decade the equipment only prices in USD/kW have been mildly increased from 1999 til 2001 and decreased from 2002 til 2004. From 2004 onwards construction prices for power projects started to rise again. For this change, several effects are likely to be the cause:

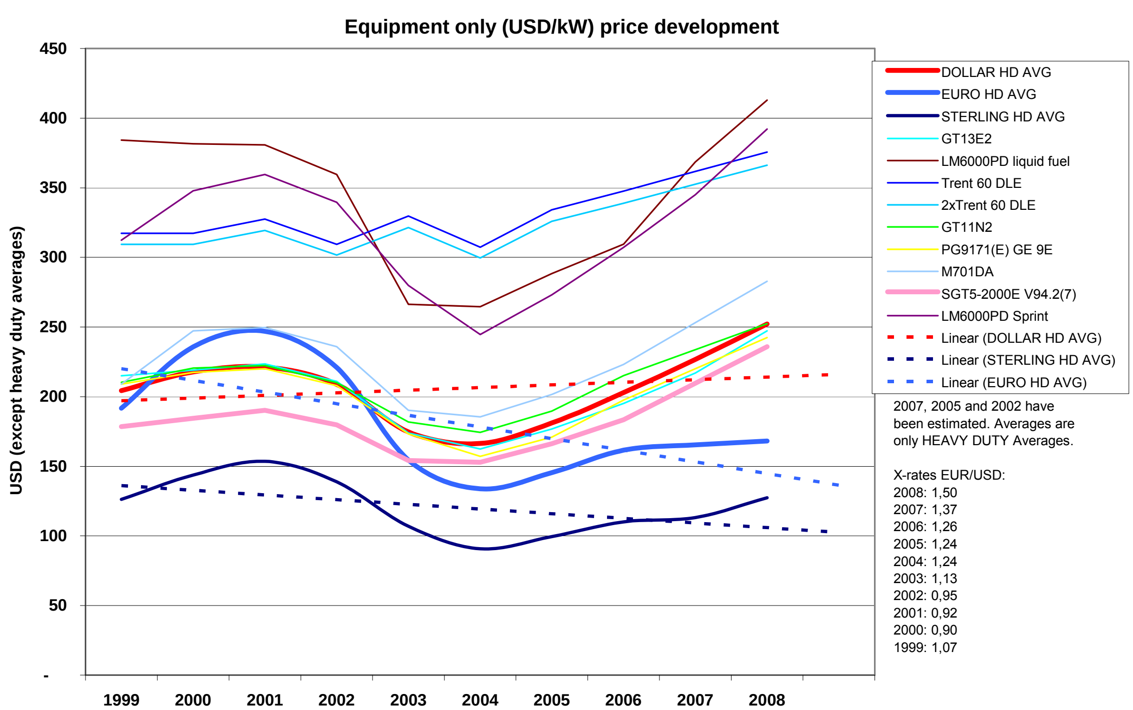
- The prices of especially steel and concrete soared as a result of growing world wide steel demand;
- New types of power plants, e.g. based on ultra super critical technology, require specialist materials which have increased more steeply then steel prices, however this is not valid for the E-type of gas turbines; and

– A worldwide surge in power projects lead to a shortage of major equipment and as a result Original Equipment Manufacturers increased their product prices.

A forecast based on a Euro or Pound Sterling long-term average would clearly lead to a lower value than would be evidenced for 2008 alone but would also provide greater stability year on year. However it may be reasonable to select shorter time periods over which to derive the smoothing approach – this would tend to allow significant changes in market prices from year to year to have a greater influence on the derived price whilst still providing a damping effect.

Over the last 10 years, equipment only prices have been in a €130 to €240/kW range, and are currently at approximately €160/kW. This could be considered as a large range. The following provides information to aid understanding of the sensitivity of the final annualized fixed costs - an increase of 10% in the Capex costs would lead to an increase in the annualized fixed costs of around €5/kW (or around 6.5% on the currently proposed BNE).

FIGURE 2
HISTORIC EQUIPMENT ONLY COSTS OVER 10 YEARS



A further consideration to assist in smoothing volatility relates to the determination of the WACC. The WACC is determined by using the CAPM-formula. The parameters in this formula are sensitive to market movements in treasury yields and BBB-spreads. Moreover, the WACC is also sensitive to inflation. This sensitivity is especially true for the real risk free rate of return. Currently, the nominal yield on treasury bonds is lower, while at the same time inflation and BBB-spreads are higher, than the averages over the last ten years. Several Regulators, including Ofgem, have acknowledged this sensitivity drawback of the CAPM formula. Consequently they have opted for a moving average of the real risk free rate of return, or opted for a correction on current market values. The SEMC recognises that that such volatility measure reduces the price risk for both consumers and the industry. However, the SEMC does consider a calculation that can be double checked is preferable, thus ruling out this correction methodology.

The SEMC would therefore like to invite respondents to comment on the following options:

(a) Compute the WACC based on figures of treasury bonds, BBB-spread and inflation, on a certain fixing date, e.g. 30 days before publication of the final decision; on the BNE peaking costs;

(b) Compute the WACC based on the past year monthly averages of treasury bonds, BBB-spread and inflation; or

(c) Compute the WACC based on the past ten year monthly averages of treasury bonds, BBB-spread and inflation.

Respondents are invited to consider the above information and provide thoughts on applicability to the CPM for the SEM and whether it would be appropriate to apply such mechanisms for 2009 and onwards.

X. INDICATIVE ANNUAL CAPACITY PAYMENT SUM (ACPS) 2009

As previously described, the calculation of the ACPS involves the calculation of two factors, a volume (Capacity Requirement) and a price (BNE fixed costs). While this document focuses on the price element, the volume component is also a workstream that has been progressed in parallel.

Though the volume component calculation is not yet finalised, the SEMC has, with the noteworthy assistance of the System Operators, produced an indicative value for the Capacity Requirement for the 2009 calendar year of 7,320 MW. This compares to a final value for the 2008 year of 7,211 MW. The increase is primarily due to load growth.

Using this indicative value for the Capacity Requirement and the BNE Price suggested herein, the indicative ACPS for 2009 is €594,676,800.

Further detail on the Capacity Requirement calculation for 2009 will be published in the final 2009 CPM decision document.

XI. VIEWS INVITED

While views are invited on any of the issues raised in this consultation document, the SEMC is particularly eager to receive comments on the following key questions:

1. Does the proposed Siemens 2000E adequately meet the criteria expected for a Best New Entrant peaking plant in the SEM?
2. Are the assumptions and estimates contained herein pertaining to the BNE peaking plant reasonable?
3. What horizon of historical data should be used in evaluating the EPC costs for the BNE plant? Possible options are
    a. Use spot values (this is the current method);
    b. Use an average (arithmetic mean) over a horizon of several years. (Views invited as to the appropriate horizon);
    c. Use a weight-average (weighted mean) over a horizon of several years. (Views invited as to the appropriate horizon and weighting variables / parameters);
    d. Other suggestions – are there more sophisticated (for example forward-looking) means of valuing the EPC cost that a rational investor in peaking technology would face?
4. In the light of more recent precedents on Equity Risk Premium values, such as that set by the Competition Commission, which recently quoted a range of 2.5% to 4.5% in its decision regarding Heathrow and Gatwick airports, should the 5.5% value used in last year's calculation be revised?
5. What horizon of historical data should be used in determining the WACC for the BNE peaker? Detailed suggestions are listed in Section IX.

Responses to this consultation document are requested by **4pm on Friday the 1st August 2008** and should be sent to colin.broomfield@niaur.gov.uk and to tadhg.obriain@niaur.gov.uk. The SEMC intends to publish all comments received. Those respondents who would like certain sections of their responses to remain confidential should submit the relevant sections in an appendix marked confidential.