Single Electricity Market

Fixed Cost of a Best New Entrant

Peaking Plant,

Capacity Requirement

&

Annual Capacity Payment Sum for the Trading Year 2016

Decision Paper

03 Sept 2015

AIP/SEM/15/059

1 Contents

2 SUMMARY OF DECISIONS

The Best New Entrant ("**BNE**") Peaking Plant for the Annual Capacity Payment Sum ("**ACPS**") 2016 and 2017 is an **Alstom GT13E2** firing on **distillate fuel**, sited in **Northern Ireland**.

The estimated annualised fixed cost, net of estimated infra-marginal rent and ancillary service revenue, is **€72.82/kW/year.**

The Capacity Requirement for 2016 is **7070 MW.**

The product of these price and quantity elements yields an ACPS for the 2016 Trading Year of **€514,837,400.** This is a reduction of €60,116,200 compared to the 2015 ACPS.

When comparing the above figures to those proposed in the Consultation Paper ('Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2016' (SEM-15-032))[1], the following items have been reviewed and changed in calculating the final annualised fixed cost:

- Due to an update for foreign exchange rates (EUR, GBP & USD) the estimated electrical connection and operation and maintenance costs have increased. This increase also affects the Interest During Construction (IDC).

- The Weighted Average Cost Capital (WACC) has increased from 4.46% to 5.17%. A key driver for this change is the observed changes to underlying market data used to calculate the WACC, particularly in the cost of debt figures.

- The tables below show the changes between the Consultation Paper and the Decision Paper. The first two of these show Investment and Recurring cost estimates along with their relative differences between the consultation and decision. The third table shows total annual costs alongside the BNE peaking price before deductions[2].

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[1] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=879633f4-5b08-42e3-a889-4f86cf0b2667

[2] While the entire calculation was updated for a rational investor in both jurisdictions, it remained that the NI investment presented moderately better economic value than the RoI investment for both fuel types. As a result only the NI comparison is shown in the tables below (a detailed jurisdictional breakdown is provided for cost elements in the remainder of the paper).

2.1 INVESTMENT COST ESTIMATES

Table 2.1 – Comparison of Investment Costs between Consultation and Decision Papers

Cost Item	Consultation Paper (€)	Decision Paper (€)	Difference (€)
EPC Costs	94,500,000	94,500,000	0
Site Procurement	959,078	959,000	-78
Electrical connection Costs	10,529,100	16,592,000	6,062,900
Gas connection	0	0	-
Water connection	490,000	512,000	22,000
Owners Contingency	4,725,000	4,725,000	-
Financing Costs	1,890,000	1,890,000	-
Interest During Construction	848,614	624,000	-150, 614
Construction Insurance	850,500	851,000	-500
Initial Fuel working capital	3,638,868	3,527,000	-111,858
Other non EPC Costs	8,505,000	8,505,000	-
Accession & Participation Fees	3,654	4000	346
Total	**126,939,814**	**132, 688, 000**	**5,823,186**

The main difference between the consultation paper and the decision paper regarding investment cost estimates is that the connection cost has increased. This is due to updated foreign exchange rates in the calculation, and a review of the calculation itself in moving from the assumption of connection at Belfast West to a notional rural site in Northern Ireland, implemented following consideration of responses.

2.2 RECURRING COST ESTIMATES

Table 2.2 – Comparison of Recurring Costs between Consultation and Decision Papers

Cost Item	Consultation Paper (€)	Decision Paper (€)	Difference (€)
Transmission & Market operator charges	817,000	817,000	0
Gas Transportation Charges	0	0	0
Operation and maintenance costs	1,904,000	2,270,000	366,000
Insurance	1,512,000	1,512,000	0
Business Rates	753,000	767,000	14,000
Fuel working capital	165,000	182,000	17,000
Total	**5,151,000**	**5,548,000**	**397,000**

The Operation and Maintenance costs have increased compared to the consultation paper. This increase is driven mainly by a review of foreign exchange rates. The cost of the Long Term Service Agreement (LTSA) was estimated in U.S. Dollars and was then converted into Euros; this calculation was updated following consideration of responses.

2.2.1 TOTAL INVESTMENT & ANNUAL COSTS

Compared to the consultation paper, there has been an increase in Investment costs which has led to an increase in Annualised Capital Expenditure as laid out in the table below.

Table 2.3 – Comparison of Overall Costs for Alstom GT13E2 between Consultation and Decision Papers

Cost Item	Units	Consultation	Decision	Difference
Total Investment Costs	€m	123.30	129.24	5.94
Land and Residual Fuel Value	€m	1.92	1.61	-0.31
Initial Working Capital	€m	5.71	5.62	-0.09
Total Annual Costs	€m	14.92	16.47	1.55
Plant Size	MW	195.7	195.7	0
Pre Tax WACC	%	4.46	5.17	0.71
Plant Life	Years	20	20	0
Estimated BNE cost (before reductions)	**€/kW/year**	**76.24**	**83.74**	**7.50**

The final key change from the consultation paper, indicated in the table above is the increase in the Pre-tax WACC from 4.46% to 5.17%. As is discussed in more depth later, this increase is driven mainly by a movement in underlying market indices including the Risk Free Rate and spreads on sovereign and corporate bond yields since the consultation paper was published. The debt gearing settings have also been modified down from 60% to a low / high range of 20% / 40%. The change in gearing also led to a corresponding change in the equity beta.

2.2.2 ANNUALISED COSTS OF BNE PEAKER

The fixed costs associated with a BNE peaking plant have increased compared to the consultation paper by €7.50 per kW/Yr. The driving factor for this increase is an increase in the

WACC figure (see Section 7.2.2) and an increase in electrical connection costs (see Section 5.2.1).

Table 2.4 – Comparison of ACPS for 2016 between Consultation and Decision Papers

ACPS	Consultation	Decision	Difference
Annualised Cost /kW/Year	**76.24**	**83.74**	7.50
Ancillary Services (€)	4.64	4.64	0
Infra-Marginal Rent (€)	6.10	6.28	0.18
BNE Cost /kW/Year	**65.50**	**72.82**	7.32
Capacity Requirement (MW)	7070	7070	0
Annual Capacity Payment Sum (€)	**463,108,448**	**514,837,400**	51,728,952

The comparative values for the ACPS components in the consultation and this decision paper, alongside the 2015 ACPS Decision, are shown below:

Table 2.5 – Comparison of ACPS 2016 between Consultation, Decision & 2015 figures

Line Item	Decision 2015	Consultation 2016	Decision 2016
Annualised Cost (/kW/yr)	91.88	76.24	83.74
Ancillary Services (/kW/yr)	4.53	4.64	4.64
Infra-Marginal Rent (/kW/yr)	5.75	6.1	6.28
BNE Cost (/kW/yr)	**81.6**	**65.5**	**72.82**
Capacity Requirement (MW)	**7046**	**7070**	**7070**
Annual Capacity Payment Sum (€)	**574,953,600**	**463,108,448**	**514,837,400**
Difference on ACPS 2015 (€)		-111,845,152	-60,116,200
Difference Consultation to Decision (€)			51,728,952

2.3 CALCULATION METHODOLOGY

Several respondents disagreed with a number of aspects of the calculation methodology, including the unconstrained settings for the Capacity Requirement and the method of deduction of Infra-marginal Rent from the BNE Fixed Cost. While the points raised are addressed in the main body of this report, the SEM Committee stresses that it places a high weighting on the value of consistency with the established approach, for application in the final years of the SEM.

The Committee has decided to apply a calculation methodology that aligns with previous exercises, and has not been persuaded to amend the methodology for this exercise. This decision underscores the work already performed by the RAs during 2011 and 2012 on the CPM Medium-Term Review, during which the Committee contemplated changes to the methodology in the broader interest of promoting the defined objectives of the CPM.

2.4 COMPARISON OF BNE WACC WITH OTHER PRICE CONTROL DETERMINATIONS

Some respondents questioned the divergence between the proposed value for the BNE of 4.66% and the SONI Price Control WACC consulted upon in April 2015 of 5.42%, arguing that a generation business was more risky than a network operation businesss and should therefore have a higher WACC value.

The SEM Committee notes that the SONI Price Control is anticipated to be finalised by UR in September 2015, and that common elements (‘economy-wide variables’) within the two calculations are in alignment. The overall WACC values are however different; and this is due to differences in the remaining input variables, particularly Gearing and Betas.

The SEM Committee considers that price-controlled businesses face a very different set of risks to merchant businesses. Further the Committee do not accept that the comparison in overall WACC settings between SONI and the BNE is meaningful; as the business of operating a power system is much more Opex-driven; and will tend to carry less assets compared to an investor in large scale peaking generation. The SONI WACC is explicitly adjusted upwards to reflect this specific operational gearing issue.

The SEM Committee is satisfied for the reasons stated above that there is a suitable and correct level of compatibility in the final settings for the BNE in the 2016 ACPS calculation with the decisions being concurrently made by the UR regarding the SONI Price Control.

The SEM Committee also notes that the WACC component values for RoI, while not determining the marginal plant, are in line with the Europe Economics report for ESB networks[3]; and that the RoI BNE WACC is higher than the corresponding ESB networks WACC that is currently being consulted on.

3 CONSULTATION

On 11 May 2015 the Regulatory Authorities ("**RAs**") published a consultation paper on the *'Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2016'* (SEM-15-032)[4]. The adopted methodology in the calculation of the BNE Peaker Costs and the Capacity Requirement replicated that of previous years.

The RAs engaged Cambridge Economic Policy Associates ("**CEPA**") in association with Ramboll ("**Ramboll**") to assist in the calculation of the fixed costs of a BNE peaking plant for 2016. CEPA and Ramboll also assisted the RAs in the review of the responses to the consultation paper. The following sections provide a summary of the proposals within the consultation.

3.1 BNE CHOICE

The proposed Technology Option for the BNE Peaker 2016 was a distillate-fired Alstom GT13E2.

3.2 ECONOMIC AND FINANCIAL PARAMETERS

Taking account of recommendations from CEPA/Ramboll, the RAs arrived at the following WACC proposals for the 2016 BNE Consultation.

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[3] http://www.cer.ie/document-detail/Distribution-Revenue-for-ESB-Networks-Ltd.-2016-to-2020/1044

[4] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=879633f4-5b08-42e3-a889-4f86cf0b2667

Table 3.1 – Proposed WACC values to be used for the BNE Peaker for 2016 (Consultation)

	Republic of Ireland		Northern Ireland (UK)	
	Low	High	Low	High
Cost of Debt	1.00%	3.00%	0.75%	2.25%
Risk-free rate	1.00%	2.50%	0.50%	1.50%
Equity Risk Premium	4.50%	4.50%	5.00%	5.00%
Asset Beta	0.50	0.60	0.50	0.60
Debt Beta	0.10	0.10	0.10	0.10
Equity Beta	1.10	1.35.93	1.10	1.35
Post-tax Cost of Equity	6.70	7.83	6.50	7.75
Taxation	12.50%	12.50%	20.00%	20.00%
Pre-tax Cost of Equity	7.66	8.94	8.13	9.69
Gearing	60%	60%	60%	60%
Pre-tax WACC	**3.66**	**5.38**	**3.70**	**5.23**
Equivalent Vanilla WACC	*3.28*	*4.93*	*3.05*	*4.45*

3.3 LOCATION

Taking account of the factors above, and the Investment and Recurring costs in each jurisdiction and the Economic and Financial parameters, **Northern Ireland** was the preferred location for the Best New Entrant.

3.4 INFRA-MARGINAL RENT

Using the formula described in detail in the CPM Mid Term Review[5] it was proposed that **6.10/kW/yr** of Infra-Marginal Rent be deducted from the annual cost of the BNE.

[5] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=5ce2db5f-6c79-4454-9779-53dd7fae8dba

3.5 ANCILLARY SERVICES

It was proposed to deduct an allowance of **€4.64/kW/yr** for Ancillary Services from the annual cost of the BNE.

3.6 INDICATIVE BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2016

Table 3.2 – Indicative costs for BNE Peaker for 2016 (Consultation)

Cost Item	Northern Ireland Distillate
Annualised Cost per kW	€76.24/kW
Ancillary Services	€4.64/kW
Infra-marginal Rent	€6.10/kW
BNE Cost per kW	€65.50/kW

3.7 CAPACITY REQUIREMENT

A Capacity Requirement of **7070 MW** for 2016 was proposed.

3.8 RESPONSES

The RAs received sixteen responses to the consultation. These are published along with this paper. Responses were received from the following parties:

- Aughinish **("Augh")**
- Bord Gais Energy **("BG")**
- Bord na Móna **("BnM")**
- Brookfield Renewables **("Brook")**

- CBI NI **("CBI")**
- EAI **("EAI")**
- Energia **("Energ")**
- EnerNoc **("EnerN")**
- ESB **("ESB")**
- Irish Wind Energy Association **("IWEA")**
- Kore Energy **("Kore")**
- Power Procurement Business **("PPB")**
- SSE **("SSE")**
- Tynagh Energy **("Tyn")**
- Veolia **("Veo")**
- One respondent that wished to remain anonymous **("Anon")**

The responses provided were assessed and considered by the RAs and their consultants in the determination of the decisions described in this paper. In addition, discussions were held with concerned parties which also involved conference calls with the RAs' consultants.

This document includes the full calculation of the final BNE Fixed Cost, the final Capacity Requirement and the final Annual Capacity Payment Sum ("**ACPS**") for the calendar year 2016.

The 2016 Capacity Requirement has been calculated using the same methodology that has been employed in previous years. This paper also contains the data sheets used in the Adcal[6] calculation as a series of appendices.

[6] The iterative Adcal (CREEP) software is used by the TSOs to calculate the 2016 Capacity Requirement.

4 TECHNOLOGY OPTIONS

4.1 TECHNOLOGY OPTIONS FROM CONSULTATION PAPER

In the consultation paper (SEM-15-032) the RAs detailed the approach used in determining the technology to be used for the BNE Peaker. A long list of options (including both gas and dual fuelled units) was initially assessed using the selection criteria defined. This process resulted in a shortlist of five options. From these a screening curve analysis was completed resulting in a final proposal.

The proposed technology option for the BNE Peaker 2016 and 2017 is the **Alstom GT13E2.**

4.2 COMMENTS RECEIVED ON TECHNOLOGY OPTIONS

Three respondents (BG, PPB & one anonymous) provided comments in relation to the technology option proposed in the consultation paper. A number of respondents welcomed the added transparency and comprehensive approach to the selection process and the inclusion of costs for both the gas and distillate fuel options. The technology section was completed in line with previous consultations. The main areas where concerns were raised are:

- Technology Choice and Environmental Requirements; and
- Grid Code Compliance

The specific comments relating to these areas are discussed below.

4.2.1 TECHNOLOGY CHOICE AND ENVIRONMENTAL REQUIREMENTS

BG Energy argued that low carbon and energy efficiency issues would be taken into account by an investor when selecting the technology for the plant. They suggested that investment in fast-ramping conventional capacity is needed to facilitate the penetration of renewables in the SEM and I-SEM.

4.2.2 GRID CODE COMPLIANCE

SSE note that if the BNE Plant cannot meet Grid Code Requirements (specifically with regard to Leading and Lagging Power Factors) then the costs of ensuring compliance or the penalty for failure to comply must be deducted from the revenue received.

Aughinish note that the implications on plant reliability could be compromised with regards to the revised Grid Code.

4.2.3 PLANT LIFE

Poyry, on behalf of the EAI commented on the range of possible values that might apply for the economic life of the investment, concluding that a range from 15 to 20 years or longer may be justifiable.

4.3 SEM COMMITTEE’S RESPONSE TO COMMENTS ON TECHNOLOGY OPTION

Regarding the technology choice, in the process of developing the consultation document the RAs and CEPA/Ramboll sought to ensure consistency with criteria used in previous years and to use criteria which reflected the needs of the system.

The process that CEPA/Ramboll employed for the first initial filtering of likely technology options available to be chosen as a BNE allowed for those that were going to be Grid Code compliant. Specifically, we note that Irish Grid Code compliance, particularly in terms of leading power factor capability, is expected to be less onerous for smaller units, such as the GT13E2 than for those (say) employed at the Aghada CCGT plant in Ireland that utilises an Alstom gas turbine generator.

The SEM Committee agree with CEPA’s assessment regarding plant life, that there is not sufficient evidence to suggest that 20 years should be changed.

4.4 DECISION ON TECHNOLOGY OPTION

The SEM Committee are content that a rigorous assessment has been made of the technologies available and the proposal as detailed in the consultation should be chosen as the BNE Peaker for 2016.

The Technology Option for the BNE Peaker in 2016 and 2017 is the <u>Alstom GT13E2</u>

5 INVESTMENT COSTS

5.1 INVESTMENT COSTS FROM CONSULTATION PAPER

Within the consultation, the key areas given consideration were:

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

The table below summarises the investment costs within the consultation:

Table 5.1 – Consultation Paper summary of Investment Costs

Cost Item	NI Distillate	NI Dual Fuelled	RoI Distillate	RoI Dual Fuelled
EPC Costs	€94.500	€95.600	€95.700	€96.900
Site Procurement	€0.959	€0.950	€0.767	€0.760
Electrical connection Costs	€10.529	€10.529	€6.970	€6.970
Water connection	€0.490	€0.490	€0.490	€0.490
Gas connection	€0.000	€3.620	€0.000	€3.620
Owners Contingency	€4.725	€4.780	€4.785	€4.845
Financing Costs	€1.890	€1.912	€1.914	€1.938
Interest During Construction	€0.849	€0.880	€1.109	€1.153
Construction Insurance	€0.851	€0.860	€0.861	€0.872
Initial Fuel working capital	€3.639	€3.057	€2.962	€2.488
Other non EPC Costs	€8.505	€8.604	€8.613	€8.721
Accession fees	€0.001	€0.001	€0.000	€0.000
Participation Fees	€0.003	€0.003	€0.000	€0.000
Total	**€126.940**	**€131.286**	**€124.171**	**€128.757**

5.2 COMMENTS RECEIVED ON INVESTMENT COSTS

5.2.1 CONNECTION COSTS

Electrical Connection Costs

Energia and NIE PPB believe that the relative strength of the Euro against the GBP is not reflected in the calculation of electrical connections costs within the consultation paper.

Gas Connection Costs

PPB notes that the cost of the gas connection for the Northern Ireland unit should reflect the change in exchange rate between Sterling and Euro. They also query that the consultation paper assumes the cost of gas connection has not increased, despite inflation in labour and materials over the period.

Energia note that the Gas connection costs are based on the 2014 BNE calculation, since this was 6 years ago there is no reason as to why the gas costs have not increased.

Water Connection Costs

Energia note that since the figures are based on the BNE 2010 calculation, these water connection costs should have increased.

5.2.2 SITE PROCUREMENT COSTS

Energia believe ”It cannot be assumed that a plant setting up would be able to purchase land at the referenced rate. The cost of the land is influenced by the nature of the business setting up. As the figure here does not take this into account it is likely that the cost of land here is being underestimated. The recent upturn in the economy is also likely to have a bearing on the cost of land.”

5.3 SEM COMMITTEE’S RESPONSE TO COMMENTS ON INVESTMENT COSTS

5.3.1 CONNECTION COSTS

Electrical Connection Costs

Following discussion with CEPA and contemplation of the points raised by respondents, the SEM Committee has endorsed an amended calculation for electrical connection costs, resulting in an increase to €16.592m in NI and €9.690m in RoI. The new approach is explained in detail within CEPA’s report (page 8).

Gas and Water Connection Costs

Following discussions with CEPA with regards to comments raised by respondents the SEM Committee has endorsed a revision for inflation as suggested by respondents. The proposed approach which sets consistent costs between NI and RoI laid out in the consultation paper is however retained.

5.3.2 SITE PROCUREMENT COSTS

Further analysis was undertaken by CEPA to establish accurate values for site procurement. Table 5.2 below shows that as a consequence the estimated electrical connections costs have increased.

5.4 DECISION ON INVESTMENT COSTS

Taking account of the responses received, the revised investment costs for the Alstom GT13E2 are shown below:

Table 5.2 – Decision Paper summary of Investment Costs (€m)

Fuel Type	NI Distillate	NI Dual Fuelled	RoI Distillate	RoI Dual Fuelled
EPC costs	€94.500	€95.600	€95.700	€96.900
Site procurement cost	€0.959	€0.950	€0.767	€0.760
Electrical Connection costs	€16.592	€16.592	€9.690	€9.690
Water connection costs	€0.512	€0.512	€0.512	€0.512
Gas connection costs	€0.000	€3.785	€0.000	€3.785
Owners contingency	€4.725	€4.780	€4.785	€4.845
Financing costs	€1.890	€1.912	€1.914	€1.938
Interest During Construction	€0.624	€0.648	€0.780	€0.812
Construction insurance	€0.851	€0.860	€0.861	€0.872
Initial fuel working capital	€3.527	€2.963	€2.837	€2.383
Other non EPC costs	€8.505	€8.604	€8.613	€8.721
Accession fees	€0.001	€0.001	€0.000	€0.000
Participation fees	€0.003	€0.003	€0.000	€0.000
Total	**€132.688**	**€137.210**	**€126.460**	**€131.218**

6 RECURRING COST ESTIMATES

6.1 RECURRING COSTS FROM CONSULTATION PAPER

The recurring costs within the consultation paper are summarised as follows:

Table 6.1 – Consultation Paper Summary of Recurring Costs (€m)

Fuel Type	NI Distillate	NI Dual Fuelled	RoI Distillate	RoI Dual Fuelled
Market operator charges	€0.009	€0.010	€0.009	€0.010
Electricity transmission charges	€0.808	€0.841	€1.359	€1.416
Gas transportation charges	€0.000	€0.000	€0.000	€0.000
Operation & Maintenance	€1.940	€1.970	€1.940	€1.970
Insurance	€1.512	€1.530	€1.531	€1.550
Business rates	€0.753	€0.784	€1.532	€1.597
Fuel working capital (ongoing)[7]	€0.165	€0.139	€0.137	€0.115
Total	**€5.187**	**€5.273**	**€6.509**	**€6.658**

6.2 COMMENTS RECEIVED ON RECURRING COST ESTIMATES

Energia note that "as O&M, insurance and rates seem to only have increased in line with general market changes and have ignored the exchange rate. It would be expected that units based in NI would have increased more in euro terms due to the substantial increase in the value of Sterling. Any estimation of these costs should reflect the exchange rate and market increases."

6.3 DECISION ON RECURRING COST ESTIMATES

Taking the comments received from respondents into account, the estimates of the recurring costs of the Alstom GT13E2 are summarised below:

[7] Similar to the approach taken in previous years we have included an opportunity cost for holding fuel at the plant. This is calculated as the initial cost of the fuel multiplied by the WACC.

Table 6.3 – Decision Summary of Recurring Costs

Fuel Type	NI Distillate	NI Dual Fuelled	RoI Distillate	RoI Dual Fuelled
Market operator charges	€0.009	€0.010	€0.009	€0.010
Electricity transmission charges	€0.808	€0.841	€1.359	€1.416
Gas transportation charges	€0.000	€5.816	€0.000	€0.000
Operation & Maintenance	€2.270	€2.300	€2.270	€2.300
Insurance	€1.512	€1.530	€1.531	€1.550
Business rates	€0.767	€0.799	€1.532	€1.597
Fuel working capital (ongoing)[8]	€0.182	€0.153	€0.147	€0.123
Total	**€5.548**	**€11.449**	**€6.849**	**€6.996**

The Fuel Option for the BNE Peaker 2016 and 2017 is Distillate

7 ECONOMIC AND FINANCIAL PARAMETERS

7.1 ECONOMIC AND FINANCIAL PARAMETERS FROM CONSULTATION

A number of assumptions were included within the consultation on the nature of the BNE investment. These assumptions are detailed below:

Table 7.1 – BNE peaking Plant Investment Assumptions

Area	Assumption
Type of Investor	It is assumed that the BNE investor is likely to be an integrated utility seeking to raise funding at the corporate level for the peaking plant investment project in

[8] Similar to the approach taken in previous years we have included an opportunity cost for holding fuel at the plant. This is calculated as the initial cost of the fuel multiplied by the WACC.

	the forthcoming year.
Plant Life	The economic life of the project has been taken as 20 years.
Financing Structure	It is assumed that an efficiently financed peaking plant would broadly seek to match the maturity of its debt profile to the anticipated project life of 20 years. Therefore an average tenor of 10 years is assumed on the new debt.
Credit Quality	It is assumed that a BNE investor has an investment grade credit rating BBB. The analysis of market data employed data for BBB grade debt which is a more conservative assumption.

Using these assumptions, the following Weighted Average Cost of Capital was calculated for each jurisdiction using a mid-point choice method from the lower and upper limit results in Table 3.1:

Northern Ireland	**4.46%**
Republic of Ireland	**4.52%**

7.2 COMMENTS RECEIVED ON ECONOMIC AND FINANCIAL PARAMETERS

All respondents commented on the economic and financial parameters proposed in the consultation and this area was the most commented upon. Comments received can be broadly categorised in three ways:

- Investor Type and its associated validity.
- Issues regarding the Weighted Average Cost of Capital (including the value of gearing applied in the WACC calculation).

7.2.1 INVESTOR TYPE

Respondents felt that the fundamental assumption that the investor type was benchmarked against a BBB rating and therefore investment grade, was wrong. They felt that a BBB rating did not reflect the observations of participants in the SEM. Many felt that the assumption at the outset should more closely reflect the nature of participants in the SEM, which may include non-investment grade entities.

7.2.2 WACC PARAMETERS

In general, respondents felt that the WACC value was too low and that the range of WACC values provided by CEPA/Ramboll was not reflective of the current market conditions. Some respondents, through their affiliation with the Electricity Association of Ireland (EAI) were signatories to a report by Frontier Economics (FE) submitted alongside responses. Key points of that report included:

- The jurisdictional values of the WACC are higher than in the CEPA/Ram report, namely 6.45% for Northern Ireland and 5.69% for the Republic of Ireland.
- The assessment of equity return led FE to use a Total Market Return (TMR) of 7.1% for Northern Ireland and 6.8% for the Republic of Ireland.
- Estimates on the cost of debt are higher in the FE report than the CEPA report. This is primarily due to the nature of the investor, namely the difference in assuming the investor to be a vertically integrated utility (CEPA) or a standalone generation investment (FE).
- The gearing levels are too high in the CEPA report, FE feel 30% debt to equity to be more appropriate (CEPA 60% D/E)
- Whilst FE acknowledge the suggestion CEPA proposed of 0.5-0.6% for the asset beta; they believe that the top end of this range should be the value chosen, not a mid-point. This points to their approach of selecting a standalone generation investor as the basis of the assumption at the outset, since then the lower end of the asset beta range would not be appropriate.
- Standalone generation would not have an investment grade, implying that their gearing levels would be in the 20-40%. Therefore to accurately describe the credit rating of a BBB rated company, 60% is too high a gearing level.

Gearing

Some responses argued that the gearing level of 60% is too high. The Frontier Economics (FE) report stated that:

"The CEPA analysis appears to put high emphasis on the gearing rates from regulated network firms (both the actual gearing rates and those applied in the regulatory determination of the WACC). However, these are not relevant for the assessment of the WACC for a new entrant generation firm. Firms with a large proportion of their business represented by generation typically have much lower gearing rate, reflecting the higher risks."

FE cite the CMA's recent assessment of the generation and vertically-integrated WACC in the current Energy Market Investigation, which concludes a 20-40% gearing level is reasonable[9].

The FE report takes into account the ratio of debt to earnings before interest, taxes, depreciation, and amortization (EBITDA) and notices that in the consultation paper the ratio is of the order of 8. With all of this in mind, FE is moved to propose a range of 20-40%, the mid-point of 30% as the absolute value of the gearing.

7.2.3 CPI & RPI INDEXATION

Some respondents noted that the ACPS was indexed in 2014 and 2015 using CPI rather that RPI inflation, and felt that an estimate of the CPI should be used to deflate the nominal cost of debt to extract the real cost of debt within the derivation of the annualised cost.

7.3 SEM COMMITTEE'S RESPONSE TO COMMENTS RECEIVED ON ECONOMIC AND FINANCIAL PARAMETERS

7.3.1 INVESTOR TYPE

The SEM Committee endorses CEPA's comment on the need for a WACC that reflects the risk profile and therefore the marginal project WACC of the BNE, rather than for the VIU business as a whole (CEPA Section 2.2).

In choosing a marginal project WACC the SEM Committee note that the employed method of 'aiming up' selects a broader range for the cost of debt. The SEM Committee are satisfied with this approach. The SEM Committee notes CEPA's advice to the RA's:

"This methodology has historically resulted in a degree of "headroom" or "aiming up" when setting a range for the cost of debt (see Figure below) to allow for the 20-year life BNE project potentially not being able to borrow at current spot rates, mean reversion to longer term historic trends of investment grade borrowing costs (if any refinancing is required) *and* that the *marginal* cost of debt that is reflected in the project WACC – given the underlying risk profile of

[9] https://assets.digital.cabinet-office.gov.uk/media/559fc933ed915d1592000050/EMI_provisional_findings_report.pdf

the generation investment and current and expected average costs of debt for the VIU – might be assumed to be higher by a VIU investor than a spot cost of debt derived from current market evidence of an investment grade benchmark".

The investor rating of BBB has remained and has not changed given the circumstances with which CEPA have undertaken their modelling. The SEM committee duly note the questions raised regarding the apparent shift in the type of investor that would invest in the SEM.

Notwithstanding these comments, the SEM committee feel that a change to the fundamental modelling assumptions would represent a major policy change in the ACPS modelling structure and would violate the well-defined and consistent approach taken in previous years.

The SEM Committee are satisfied that CEPA's method of cross checking against wider market evidence on the cost of debt for yields on non-investment grades does not change the fundamentals of the theoretical modelling of a BNE investor. The 100 bps uplift to the BBB benchmark on the high estimate boundary does not imply that the rational investor becomes rated at B+ or B-.

The SEM Committee endorses the approach taken by CEPA and are satisfied that the consistency with previous years has not been compromised.

The SEM Committee stresses that changes to the Cost of Debt are directly observed changes to market data and are not changes to any policy with regard to the methodology employed.

In accordance to previous methodologies, one of the central assumptions to the WACC calculation is to assume the BNE investor would have an investment grade rating.

The SEM Committee confirms that the marginal cost of debt for the BNE should be based on an investment grade benchmark BBB, whilst acknowledging that the broader range of evidence is needed to fulfil the best ***marginal*** cost of debt for the project.

7.3.2 WACC PARAMETERS

The RAs gave consideration to the relative changes in the market that have occurred since the consultation paper was published. The table below shows the updated version of the WACC parameters, used to calculate the ACPS.

Table 7.3 – Updated Cost of Capital Parameter Ranges (Source: CEPA)

	Republic of Ireland		Northern Ireland (UK)	
	Low	High	Low	High
Cost of Debt	2.00%	3.50%	1.45%	2.75%
Risk-free rate	1.50%	2.50%	1.25%	
Equity Risk Premium	4.50%		5.25%	
Asset Beta	0.54	0.58	0.54	0.58
Debt Beta	0.1	0.1	0.1	0.1
Equity Beta	0.65	0.90	0.65	0.90
Post-tax Cost of Equity (real)	4.43%	6.55%	4.66%	5.98%
Taxation[10]	12.50%	12.50%	18.28%	18.28%
Pre-tax Cost of Equity (real)	5.06%	7.49%	5.71%	7.31%
Gearing	20%	40%	20%	40%
Pre-tax WACC (real)	**4.45%**	**5.89%**	**4.85%**	**5.49%**
Mid-point (pre-tax, real)	**5.17%**		**5.17%**	

The increase in WACC over both jurisdictions reflects the most up to date market evidence. By this we mean that yield information (used as a benchmark for assessing the cost of capital) has been shown to increase. The SEM Committee acknowledge that the initial report of February 2015 observed an historic low on government bond yields.

The SEM Committee reject the notion set out in CEPA's paper (page 28) that the point estimate for the WACC should be found by taking the 75th percentile of the low-high range estimates. The change to this method would signify a break in approach and the Committee prefers the maintenance of the use of mid-point estimates for the WACC throughout the decision paper. Another reason for the decision to take the mid point is that the WACC ranges for the low-high estimates is now broader than in the consultation paper, due to increases in the cost of debt.

[10] In the UK Budget 2015, it was announced that the UK corporation tax rate would fall from 20% to 19% in 2017, and then to 18% in 2020. Our tax estimate reflects the average corporate tax rate over the twenty year economic life of the plant, based on these assumptions.

The SEM committee are satisfied that this broader range in the cost of debt sets out enough marginal risk for the project, and as such this strengthens the SEM Committee's decision to continue to take a midpoint estimate.

7.3.3 COST OF EQUITY

The SEM Committee's position is to amend the Risk Free Rate and the Equity Risk Premium to 1.25% and 5.25% respectively. The SEM Committee concur with the approach taken by CEPA in cross-checking to the CMA's ongoing investigation to Bristol Water. The SEM Committee are satisfied with a Total Market Return of 6.5%.

Overall the cost of equity analysis put forward by CEPA addresses the respondents' call for "highlighting the challenging environment for European generation since 2013 and the increased market and regulatory risks that are affecting the all-island electricity market".

7.3.4 COST OF DEBT

CEPA have addressed the comments in some depth in their recommendation report (pages 9-11).

CEPA's recommendation of including a Northern Ireland Debt Premium of 25 bps is not included in our cost of debt calculation. The SEM Committee feel that the evidence presented by CEPA on the Northern Ireland Debt Premium is not sufficient to warrant an inclusion to the cost of debt ranges and is therefore omitted. The SEM Committee's decision to not include the NI Debt Premium is further supported by the CMA's decision to not support a risk premium in NIE's final price determination in 2014[11].

The SEM Committee agree with the 'aiming up' rationale and that the *marginal* cost of debt assumed by the investor in setting the *project* WACC is therefore higher than the investment grade benchmarks as set out in CEPA's report.

The SEM Committee have decided to include a 20 bps issuance inclusion for new debt, as such this appears in both the lower and upper bounds for each calculation.

[11] https://assets.digital.cabinet-office.gov.uk/media/535a5768ed915d0fdb000003/NIE_Final_determination.pdf

7.3.5 GEARING

The SEM Committee notes the useful bilateral discussions held with respondents following the consultation paper and the advice of CEPA. The Committee had proposed a gearing of 60% in line with previous exercises in the consultation paper, but is persuaded to modify this to a range between 20% and 40% following consultation, because:

- Evidence for this was provided from several respondents including some compelling material from well qualified sources presented in support of bilateral discussions
- The setting of a lower gearing is compatible with the retention of an Investment Grade credit rating; it is clear that higher gearing makes a project more risky from a lender's perspective
- CEPA have also endorsed the amendment on reflection of the evidence provided by respondents

The Committee notes that, though the casting of the investor at 20% to 40% debt is a material change in the investor characteristic, the impact on the WACC calculation in fact turns out to be marginal, as the reduction in gearing is offset by a compensatory movement in Equity Beta.

7.3.6 CPI & RPI INDEXATION

Some responses centred on the indexing to CPI and the potential inconsistency in applying a deflationary RPI figure to convert nominal yields to real ones.

The SEM Committee note that CEPA agree with respondents regarding the indexation of the ACPS by CPI *and* the deflation of nominal yields to real by the same index. The SEM Committee also agree with respondents insofar as to the need for a consistent method, but disagree with the index that is applied.

The SEM Committee notes that there is standing precedent in WACC calculation methodologies used in price controls in Northern Ireland and across the UK in recent years (as well as previous ACPS calculations) for the use of RPI. The Committee has decided to retain its method to deflate the nominal yields to real via RPI within the WACC calculation, but index the ACPS for 2017 using an RPI-based multiplier.

The SEM Committee acknowledges that CEPA have updated their report to reflect this decision (see CEPA WACC Report Section 3.3.1).

The SEM Committee acknowledge that this is a change in approach to the setting of the 2017 ACPS compared to the indexing exercise undertaken for the 2014 & 2015 ACPS's but that on balance, is of the view that this is the best means of obtaining consistency in the application of indexations within the SEM CPM.

8 BEST NEW ENTRANT PEAKER FOR 2016 AND 2017

8.1 CONSULTATION PAPER

The summary of the annualised costs for a distillate fired Alstom GT13E2 within the consultation paper were as follows:

Table 8.1 – Overall Cost of a distillate fired BNE Plant in NI and RoI (Consultation)

Line Item	Unit	NI	RoI
Total investment costs	€ million	123.30	121.21
Land and Fuel Residual Value	€ million	1.92	1.54
Initial Working Capital	€ million	5.71	5.02
Total Annual Costs	€ million	14.97	16.11
Plant Size	MW	195.7	195.7
Pre Tax WACC	%	4.46%	4.62%
Plant Life	Years	20	20
Estimated BNE cost (before reductions)	€/kW	**76.24**	**82.31**
Inframarginal Rent	€/kW	6.10	
Ancillary Service revenues	€ 000/annum	4.64	
Estimated BNE cost	€/kW	**65.50**	

Several respondents commented on the use of the exchange rate and the Pound's associated strength against the Euro.

The SEM Committee acknowledges the comments made on the impact of choosing the most up to date exchange rate. The Euro to GBP rate was updated with reference to the IMR distillate bid price of Section 9 below, and also is applied in the updates to the electrical connections costs and operation and maintenance costs.

8.2 DECISION ON BNE PEAKER 2016 AND 2017

Following revision in light of comments received to the consultation, the overall costs of the BNE peaker for 2016 and 2017 have been reassessed. The results are shown in the table below:

Table 8.2 – Decision: Overall Costs of a Distillate Fired BNE in NI and ROI

Line Item	Unit	NI	RoI
Total investment costs	€ million	129.16	123.62
Land and Fuel Residual Value	€ million	1.64	1.31
Initial Working Capital	€ million	5.62	4.91
Total Annual Costs	€ million	16.39	17.20
Plant Size	MW	195.7	195.7
Pre Tax WACC	%	5.17%	5.17%
Plant Life	Years	20	20
Estimated BNE cost (before reductions)	€/kW	**83.74**	**87.91**
Inframarginal Rent	€/kW	6.28	
Ancillary Service revenues	€/kW	4.64	
Estimated BNE cost	€/kW	**72.82**	

The Best New Entrant Peaker for 2016 and 2017 is the Alstom GT13E2, located in Northern Ireland and uses Distillate fuel

9.1 INFRA MARGINAL RENT FROM CONSULTATION PAPER

Infra-marginal rent is deducted from the BNE using the following formula:

IMR DEDUCTED IN €/kW = [(PCAP – BID)/1000] * OUTAGE TIME * (1 – FOP)

In the Consultation Paper the RAs used the average bid price, in Euro, of all existing Distillate units in the SEM on 31st March 2015 as a proxy for the bid price of the BNE. This bid price consisted of an average of No Load and Price-Quantity pairs. The resulting inputs and Infra-Marginal Rent were therefore:

Table 9.1 – Consultation: IMR Deduction Calculation

Item	Value
Price Cap (€/MWh)	1000
Outage Time (Hours)	8
BID Price of Peaker (€/MWh)	189.7
FOP	5.91%

IMR DEDUCTED IN €/kW = [(1000 – 189.7)/1000] * OUTAGE TIME * (1 – 5.91%)

= €6.10/kW

9.2 COMMENTS RECEIVED ON INFRA MARGINAL RENT

Through the Electricity Association of Ireland (EAI) and the Poyry Report, some respondents expressed the view that the determination of IMR does not reflect real market observations.

All respondents on the IMR issue were of the view that the use of 8 hours LOLE used in the IMR derivation is unrealistic.

Respondents felt that since the Price Cap (PCAP) has been reached only once since the SEM began and since the BNE peaker would earn (in 16 consecutive trading periods) the difference between its bid price and the PCAP, this is not reflective of the SEM and that the IMR methodology does not capture an accurate picture.

The referenced Poyry report can be broadly summarised into three streams of argument:

1. The approach to ‘fix’ the IMR deduction each year is noted as inconsistent with the stated intention of the CPM as providing a degree of financial certainty to generators and a stable pattern of capacity payments.
2. The IMR value is calculated out of line with recent SEM experience, and
3. The Loss of Load Expectation (LOLE) used in the IMR derivation is an unrealistic expectation of an equilibrium market position.

The Poyry report highlights apparent inconsistencies between the previous and current methodology in calculating IMR and questions as to whether the 8 hour LOLE assumption is reflective of the actual experience of a peaking plant within the SEM.

9.3 SEM COMMITTEE'S RESPONSE TO COMMENTS ON INFRA MARGINAL RENT

The SEM Committee do not agree that multiple start costs should be included within the eight hour period when the BNE would be scheduled to run. The SEM Committee are of the view that it is reasonable to assume in the calculation that start costs of a distillate peaking plant are incorporated into the IMR methodology only once.

For the consultation paper, the average distillate bid price on 31 March 2015 (the same date as other commodity prices and exchange rates used in the calculation of the BNE were taken) was calculated, based on Commercial Offer Data of distillate units in both Northern Ireland and Republic of Ireland.

The SEM Committee maintain that the average BNE bid price should continue to be calculated using the bid price of distillate units on an all-island basis. The location of the BNE would not have any significant impact upon this price. The estimated bid has been recalculated with reference to Commercial Offer Data (COD) in August 2015; as bids have decreased somewhat since February, the resulting IMR deduction has increased.

The SEM Committee will not be re-opening the IMR calculation methodology as it was a core aspect of the detailed research and consultation that took place during the Medium Term Review 2012. The Committee have decided that the decisions made following the Medium Term Review for calculation of the IMR deduction should stand and be applied in this exercise.

9.4 DECISION ON INFRA MARGINAL RENT

The RAs updated the underlying bid price of a distillate peaker functioning in the SEM in August 2015. The new indicative bid price was calculated to be €166.25/MWh. The IMR deduction calculation is set out below:

Table 9.2 –Decision: IMR Deduction Calculation Parameters

Item	Value
Price Cap (€/MWh)	1000
Outage Time (Hours)	8
BID Price of Peaker (€/MWh)	166.25
FOP	5.91

IMR DEDUCTED IN €/kW = [(1000 – 166.25)/1000] * OUTAGE TIME * (1 – 5.91%)

= €6.28/kW

This figure will be recalculated for the 2017 ACPS, using updated bid data.

10 ANCILLARY SERVICES

10.1 ANCILLARY SERVICES FROM CONSULTATION PAPER

The RAs worked closely with the TSOs in calculating the appropriate costs for Ancillary Services under the new proposed criteria and formulae. The assumptions used in the AS Calculations for the consultation paper were:

Unit size is 195.7MW
Run hours is 2%
Load factor is 60%

10.2 COMMENTS RECEIVED ON ANCILLARY SERVICES

PPB and Energia note that the 2% run time assumption is unlikely as it is meant to only serve the last MW of demand on the system. They believe that AS revenues are overstated since during equilibrium conditions in an unconstrained market the last MW of demand will not be served by the BNE Peaker.

10.3 SEM COMMITTEE'S RESPONSE TO COMMENTS ON ANCILLARY SERVICES

The 2% run hour assumption was adopted for the 2012 decision and is retained for 2016 & 2017.

Regarding the points raised on the Ancillary Services Agreement, CEPA & Ramboll adopted a modelling approach proposed and developed by the TSOs. No change has been made to this.

The SEM Committee's approach, consistent with previous years, is to divide the Total Ancillary Services revenue by the capacity of the BNE of 195.7MW resulting in an Ancillary Services payment of **€4.64/kW/year**. This is deducted from the Annualised Cost.

It was questioned within the responses to the consultation whether the Ancillary Services deduction would also be fixed for the Trading Year 2017 (along with the BNE price and the infra-marginal rent deduction).

It is the intention of the RAs to deduct and amount appropriate for the DS3 services in the Trading Year 2017.

11 DECISION ON BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2016

The table below shows a summary of the costs and the final annualised cost of the BNE Peaker for 2016. This includes the deduction of any revenues obtained from Infra Marginal Rent or Ancillary Services.

Table 11.1 – Final costs for BNE Peaker for 2016

Cost Item	Northern Ireland Distillate
Annualised Cost (€/kW/yr)	83.74
Ancillary Services (€/kW/yr)	4.64
Infra-marginal Rent (€/kW/yr)	6.28
BNE Cost (€/kW/yr)	**72.82**

12 CAPACITY REQUIREMENT FOR 2016

12.1 CAPACITY REQUIREMENT FOR 2016 FROM CONSULTATION PAPER

As detailed in the consultation paper, the methodology used for calculating the Capacity Requirement for 2016 is the same as that used in previous year's calculations. The RAs detailed the parameters settings used in the calculation of the Capacity Requirement. These include the Generation Security Standard, Demand Forecasts, Generator Capacity, Scheduled Outages, Forced Outage Probabilities and the treatment of wind. This paper also contains the data sheets used in the Adcal calculation as a series of appendices.

The Capacity Requirement in the Consultation Paper was 7070 MW.

12.2 COMMENTS RECEIVED ON THE CAPACITY REQUIREMENT FOR 2016

Five respondents provided comments in relation to the Capacity Requirement Calculations.

Energia contended that the calculated capacity requirement was materially and systematically understated. This was due to the fact that according to the Generation Capacity Statement

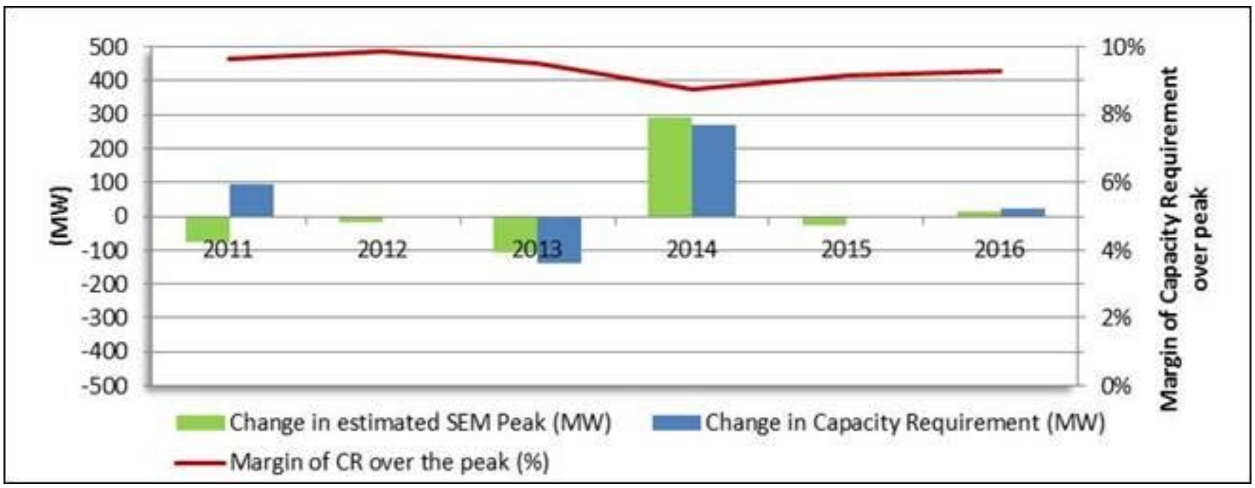
(GCS) the 7070 MW represents a mere 6% margin on TER peak and 8.2% on transmission peak. This level of margin has not been accepted anywhere on the island before.

Aughinish, BGE, BnM, Energia & PPB all note that the value of 7070 is too low when calculated in conjunction with the notion that a GSS of 8 hours LOLE assumed. Most respondents felt that a Capacity Requirement of near to 8000 MW is more appropriate for the security standard.

12.3 SEM COMMITTEE'S RESPONSE TO COMMENTS ON CAPACITY REQUIREMENT

According to CPM methodology, the Capacity Requirement is calculated with reference to the market demand. The peak of market demand is approx. 200MW less than the Total Energy Requirement peak. On this basis it is clear that the margin of the Capacity Requirement over the Market Peak is just over 9%. Over the past 6 years, it can be seen (see graph below provided by the TSOs) that this margin has been mostly in a range between 9% and 10%.

The RAs consider this Capacity Requirement to be not out of line with previous years.



The SEM Committee are satisfied with the outcomes of the Capacity Requirement calculation and the figure of 7070 MW.

The SEM Committee wish to stress that the methodology for the calculation of the Capacity Requirement was reviewed in the Medium Term Review and approved at that time by the SEM Committee. The Committee are of the view that it is not necessary to re-open this decision at this time.

The Transmission System Operators (TSOs) have been consulted in line with previous exercises to ensure maximum analytical robustness in the calculation.

12.4 DECISION ON CAPACITY REQUIREMENT 2016

The demand forecast used for the Annual Capacity Payment Sum was produced by the TSOs at the request of the SEM Committee. This demand forecast was based on the outturn for 2015 and the trends for 2012 up to the end of April.

The Capacity Requirement to be used in the calculation of the Annual Capacity Payment Sum 2016 is **7070 MW.** It is noted that this is an increase of 0.34% from the Capacity Requirement from 2015 (7046 MW).

The inputs used in the 2016 decision calculations are summarised below.

Table 12.1 – Summary of Inputs into Adcal Model

Input	Description
Load Forecasts for ROI and NI for 2016	A combined load forecast for 2016, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. The period used for analysis was 1 January 2016 to 31 December 2016. Two traces were agreed: 1) Total Load Forecast for 2016 2) Total (In Market) Conventional Load Forecast See Appendix 5 – Load Forecast for 2016
Generation Capacity	A list of all generation to be in place in 2016 was determined, including the Sent Out Capacity for each unit. For any units to be commissioned or decommissioned during 2016, the Capacity available was adjusted accordingly to reflect the actual period they are available (time weighted average). Dublin Waste to Energy and Note OCGT were not included in the model. The Time-Weighted Capacity for Conventional Generation used in the Adcal model was **9748 MW**
Wind Capacity Credit (WCC)	The most recent available Wind Capacity Credit (WCC) curve (produced by the TSOs) is used to assess the total WCC for the combined total wind installed. The Average WCC is calculated for the total installed wind. This average WCC is then applied to the time weighted total capacity for

	the Wind in the Market The Time Weighted Total Wind in 2016 used was **3464 MW**. This results in a Capacity Credit of **0.117**. The Time Weighted Market Wind Capacity in 2016 was **2729 MW**. Therefore the Wind Capacity Credit is derived as **319 MW** (2729 x 0.117)
Scheduled Outages	The Scheduled Outage Durations are determined to the nearest number of weeks and are determined from the 5 year average of scheduled outages for each unit.
Force Outage Probability (FOP)	In line with the SEM Committee decision on the CPM Medium Term Review, the FOP remains at 5.91%.
Generation Security Standard (GSS)	The SEM Committee maintained the value of **8 hours** for the GSS.

The Capacity Requirement for 2016 is 7070 MW

13 ANNUAL CAPACITY PAYMENT SUM FOR 2016

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement for 2016 as detailed in Sections 11 and 12 above, the Annual Capacity Payments Sum (ACPS) for 2016 is outlined in table 13.1 below.

Table 13.1 – ACPS for the Trading Year 2016

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2016	72.82	7070	514,837,400

The Annual Capacity Payments Sum (ACPS) for 2016 is €514,837,400

14 ANNUAL CAPACITY PAYMENT SUM FOR PREVIOUS TRADING YEARS

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2007	64.73	6,960	450,517,348
2008	79.77	7,211	575,221,470
2009	87.12	7,356	640,854,720
2010	80.74	6,826	551,133,375
2011	78.73	6,922	544,956,545
2012	76.34	6,918	528,120,120
2013	78.18	6,778	529,876,722
2014	80.27	7,049	565,819,301
2015	81.60	7,046	574,953,600

Table 14.1 – SEM Annual Capacity Payment Sums