Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement and Annual Capacity Payment Sum For Trading Year 2017

Decision Paper

SEM-16-044

05 August 2016

1 EXECUTUVE SUMMARY

The Capacity Payment Mechanism remunerates providers of generation capacity in the SEM. It is a fixed revenue mechanism which collects a pre-determined amount of money from suppliers. These funds are paid to available generation capacity in accordance with rules set out in the SEM Trading and Settlement Code. The value of this Annual Capacity Payment Sum is determined as the product of two numbers:

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

- A Price – determined as the annualised fixed costs of a best new entrant peaking plant.

The Best New Entrant ("**BNE**") peaking plant determined in 2016 was the Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland. This was determined as part of the calculation of the Annual Capacity Payment Sum ("**ACPS**") for 2016[1]. In accordance with the decision described in the 2016 Final Decision paper, its costs have been fixed and indexed for 2017.

The process for 2017 was as follows:

1. Index the 2016 BNE annualised cost by June 2016 RPI (1.6%)
2. Calculate new deductions for
   i) Inframarginal rent (based on an updated bid price), and
   ii) Ancillary Services (which includes estimates of revenues received under the new DS3 framework).
3. Calculate a new Capacity Requirement using same methodology as previous years.

The annualised fixed cost determined for the 2016 ACPS was €83.74 /kW/year. When this is adjusted for inflation[2] the 2017 annualised cost is €85.08/kW/year. Once infra-marginal rent and ancillary services revenues are deducted the cost becomes €71.45/kW/year.

The Capacity Requirement for 2017, calculated using a similar methodology to previous years, is 7267 MW.

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[1] See the Annual Capacity Payment Sum 2016 Final Decision Paper https://www.semcommittee.com/publication/sem-15-059-acps-final-decision-paper

[2] The time series can be found at https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/czbh

The product of these price and quantity elements gives an ACPS for 2017 of €519,227,150, which compares to an ACPS of €514,837,400 for the 2016 Trading Year.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2017	71.45	7267	519,227,150

Table 1.1 – Executive Summary ACPS 2017

It is important to note here that the new I-SEM will go live in Q4 2017 and as such the current Capacity Payment Mechanism will discontinue in October 2017. As such, the RAs have published the Capacity Period Payment Sum ("**CPPS**") for 2017 to indicate the monthly sums to be paid for the period Q1 2017- Q3 2017 ahead of I-SEM Go-Live:

Month	Capacity Payment Period Sum 2017
January	€52,869,006
February	€51,165,171
March	€47,229,946
April	€39,374,525
May	€36,471,362
June	€34,478,074
July	€32,716,078
August	€35,961,368
September	€35,927,804
Total until I-SEM Go-Live	**€366,193,334**
October	€45,397,053
November	€52,555,995
December	€55,080,768
2017 Grand Total	**€519,227,150**

Table 1.2 – Capacity Payment Period Sum 2017

2 CONTENTS

3 Introduction

On 1 November 2007 the Single Electricity Market ("**SEM**"), the new all-island arrangements for the trading of wholesale electricity, was introduced. 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 ("**ACPS**") from suppliers and pays these funds to available generation capacity in accordance with rules set out in the SEM Trading and Settlement Code ("**TSC**")[3]. The value of the Annual Capacity Payment Sum is determined as the product of two numbers:

- A Quantity (the Capacity Requirement) - determined as the amount of capacity required to exactly meet an all-island generation security standard; and
- A Price - determined as the annualised fixed costs of a best new entrant ("**BNE**") peaking plant.

In May 2005 the Northern Ireland Authority for Utility Regulation ("**the Utility Regulator**") and the Commission for Energy Regulation ("**CER**") (together the Regulatory Authorities ("**RAs**")) set out the options for the CPM. The RAs indicated their proposal to develop a fixed revenue CPM that would provide a degree of financial certainty to generators under the new market arrangements and a stable pattern of capacity payments. The principles outlined were incorporated in the design of the CPM and in the Trading and Settlement Code.

In March 2006 a consultation document was published that incorporated a more detailed consideration of the comments received on the design of the CPM and put forward a number of alternative options for the CPM. This paper re-iterated the proposed outline of the CPM suggesting that annual capacity payments should be fixed and that the annual fixed sum be divided into a number of within-year pots (i.e. Capacity Periods). The paper also set out proposals for the determination of the Annual Capacity Payment Sum. It proposed that the annual aggregate capacity payments should be set by multiplying an appropriate level of required generation capacity by the relevant fixed costs of a best new entrant peaking generator.

The RAs 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

[3] http://www.sem-o.com/MarketDevelopment/Pages/MarketRules.aspx

well as the estimated revenues the plant may derive through its operation in the ancillary services markets.

The same process has been used for the calculation of the fixed costs of a BNE peaking plant for all subsequent years. The Annual Capacity Payment Sums for all previous years are summarised in Appendix 1 of this paper.

On 9 March 2009 the SEM Committee ("**SEMC**") published a consultation paper titled ***Fixed Cost of a Best New Entrant Peaking Plant Calculation Methodology Consultation Paper*** (SEM-09-023). The purpose of the consultation paper was to propose options to address a key concern raised by industry participants regarding the stability of the Annual Capacity Payment Sum due to the annual determination of the Best New Entrant Fixed Cost. In the paper, the SEMC signalled its intention to carry out a further review of the CPM in the medium term. The main purpose of the review was to examine if the current design of the CPM could be further improved to better meet the CPM objectives. This review concluded in March 2012 when the SEMC published the final decision paper on the CPM Medium Term Review (SEM-12-016).

Following the Medium Term Review the SEMC decided that the BNE element of the ACPS calculation should be fixed and indexed for three years, ending the fixedness in 2015. The 2016 calculation was constructed from the ground up through the (usual) re-evaluation of the Capacity Requirement but also the BNE figure was calculated from first principles, through the contracted consultants Cambridge Economic Policy Associates (CEPA).

The SEM Committee published the consultation paper on 29 May 2015 along with the CEPA paper outlining the BNE figure. The consultation paper included proposed once again fixing the BNE element for the Trading Year 2017 to provide stability to generators in light of the SEM ending as the new I-SEM goes live in 2017. The decision paper was then published on 4 September 2016 (SEM-15-059). It was decided within the decision paper that the BNE element will be the inflated through the Retail Price Index ("**RPI**") for 2017. The SEM Committee approved to inflate through the RPI rather than the previously used Consumer Price Index ("**CPI**"). The deduction for System Services revenues will be implemented for 2017 using estimated DS3 revenues which supplants the previously deducted Harmonised Ancillary Services ("**HAS**").

4 Consultation

On 18 May 2016, the RAs published a consultation paper on the *'Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement and Annual Capacity Payment Sum for Calendar Year 2017'* [4].

4.1 BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2017

In the decision paper on *'Fixed Cost of a BNE peaking plant, Capacity Requirement and Annual Capacity Payment Sum for the Calendar Year 2016'*[5], the BNE for 2016 and 2017 was determined as an Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland.

The table below provides a summary of the final annualised costs of the BNE Peaker for 2015 and 2016 with the final 2017 figures. This includes the deduction of any revenues obtained from Infra Marginal Rent, and Ancillary Services.

	Decision 2015	Decision 2016	Decision 2017
Annualised Cost per kW per year	91.88	83.74	85.08
Ancillary Services	4.53	4.64	N/A
DS3 Revenues	N/A	N/A	7.34[6]
Infra-Marginal Rent	5.75	6.28	6.29[7]
BNE Cost per kW per year	**81.60**	**72.82**	**71.45**

Table 4.1 – Final Decision: BNE Prices

[4] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-026%20ACPS%202017%20Consultation%20Paper%20for%20Publication_0.pdf

[5] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-15-059%20ACPS%20Final%20Decision%20Paper.pdf

[6] Based on a remodelling of the DS3 revenues to omit any monies earned from DRR, FPFAPR and FFR and new tariff rates.

[7] Based on an average SEM distillate price of €164.56 /MWhr observed 21 June 2016

4.2 CAPACITY REQUIREMENT FOR 2017

The methodology used for calculating the Capacity Requirement for 2017 was the same as used in previous years' calculations and was outlined in the consultation paper. As a result of analysis carried out in conjunction with the TSOs, the RAs proposed that the Capacity Requirement for 2017 should be **7267 MW**.

4.3 FCPP_y AND ECPP_y FOR 2017

The Fixed Capacity Payments Proportion (FCPP_y) sets the proportion of each monthly Capacity Period Payment Sum to be allocated on a fixed basis. This is based on a demand forecast and the payments are set before the start of the year.

The Ex-Post Capacity Payment Proportion (ECPP_y) sets the proportion of each monthly Capacity Period Payment Sum to be allocated according to the ex-post Loss of Load Probability (LOLP) in each Trading Period in the month. The payments are determined after the end of each month.

A third value, the Variable Capacity Payment Proportion(VCPP_y) is implicitly derived from the values of FCPPy and ECPPy. This is set such that:

$$\boldsymbol{VCPP_y = 1 -} \ (\mathbf{FCPP}\ _{\boldsymbol{y}} + \ \mathbf{ECPP}_{\boldsymbol{y}})$$

The $\boldsymbol{VCPP_y}$ sets the proportion of each monthly Capacity Period Payment Sum to be allocated according to the forecast LOLP for each Trading Period in the month. These payments are determined before the start of the month.

Since the start of the SEM, these parameters have been set at the following values:

$$\mathbf{ECPP}_{\boldsymbol{y}} = \mathbf{0.3}$$
$$\mathbf{FCPP}\ _{\boldsymbol{y}} = \mathbf{0.3}$$
$$\boldsymbol{VCPP_y} = \mathbf{0.4}$$

Within the consultation, the RAs did not propose changing the payment proportions for 2017.

5 CONSULTATION RESPONSES

The RAs received nine responses to the consultation from the following parties:

- AES
- Bord Gáis (BG)
- Bord na Móna (BnM)
- Brookfield Renewables
- Electricity Association Ireland (EAI)
- Energia
- Irish Wind Farm Association (IWEA)
- Power NI Energy Ltd Power Procurement Business (PPB)
- Tynagh Energy Ltd (TEL)

These responses are summarised below and are published in full along with this decision paper.

5.1 SUMMARY OF COMMENTS RECEIVED

Inframarginal Rent Deduction

Energia, BG and **PowerNI PPB** argued that the inclusion of an InfraMarginal Rent (IMR) figure has no place in the calculation since they considered that the IMR is never actually earned. Each respondent argued that there is fundamental disconnect between the IMR deduction in the ACPS and the reality of market revenues earned by an actual 'new entry' 'peaking' unit in the SEM.

DS3 Deduction

The determination of the DS3 System Services revenues was put forward in the consultation paper. The calculation of this figure was an area of concern for **AES**, **EAI** and **Energia** as there is insufficient evidence and justification to support the value of the proposed increase in DS3 System services revenue and an implied reduction in overall capacity.

BG considered that the application of Performance Scalars are missing from the consultation exercise; which leads to a reduction in the BNE's potential revenues. **Brookfield** add that there is not adequate transparency in the determination of the Ancillary Services deduction stemming from the complexities of the interim tariffs, since they contain both Product and Performance Scalars.

BnM consider that there is little transparency with regards to this deduction and the RAs have assumed that the performance Scalars are all set to unity for the BNE, whereas this may not necessarily the case. This is to assume that the BNE is at no risk of offering no services for an entire year, which is an unreasonable assumption.

The Performance Scalar that is to be applied is an industry average according to **BG**, and must be included in the model.

Almost all respondents believe that the interim tariff arrangements will not offer any payments for Fast Frequency Response (**FFR**), Dynamic Reactive Response (**DRR**) and Fast Post Fault Active Power Recovery (**FPFAPR**) since these services are not included in the interim tariff arrangements.

TEL noted that the 2014 Procurement Decision Paper states that the generators will be paid irrespective of constraints on the better of Market or Dispatch position. This is contrary to the Interim Tariffs consultation paper which states that the payments are settled on dispatch only.

Energia note that there is an issue over whether the BNE would qualify for DS3 services at all. This is due to the qualification process for new providers. They feel there is insufficient evidence to support the claim that the BNE would qualify for DS3 services.

They further note that the capability of 195.7 MW of 'Replacement Reserve – Synchonised' (**RRS**) should have been listed in the appendix as 78.28 MW and not what was printed. The unit cannot offer that level of capability of 195.7 MW during 2 % runtime whilst operating at 60% load factor.

The **EAI** and **BnM** note that he Ancillary Services deduction should not be modelled on an estimate of DS3 revenues but simply be calculated though a indexation of the 2016 Harmonised Ancillary Services (HAS) deduction.

The Capacity Requirement for 2017 and Generation Security Standard (GSS)

PowerNI PBB note that a 2017 Capacity Requirement of 7267 MW relative to a Total Energy Requirement (TER) of 6888 MW results in a 5.5% plant margin, which highlights that the requirement would not provide an 8 hour Generation Security Standard (GSS). **Energia** note that the continued use of a 8 hour Loss of Load Expectation (LOLE) is not based in reality.

All respondents noted that is incorrect to use a GSS of 8 hours in the determination of the fixed cost of running the BNE.

5.2 RESPONSES TO COMMENTS RECEIVED

Deduction for DS3 services

The SEM Committee have decided that BNE will qualify for DS3 revenue payments as although the qualification process is not yet final, the Alstom GT13E2 would qualify based on the strong performance track record the RAs considered during the technology options phase of the consultation process for the Trading Year 2016. The Alstom GT13E2 has been chosen as the preferred technology option in the years 2007-08, 2010-2016.

The RAs have applied the final tariff rates approved by the SEM Committee in deriving the final value for the fixed BNE cost in 2017. This has led to a reduction in estimated revenue from €7.67/kW to €7.34/kW. The main driver for this is the reduction in tariff rate that will be paid for de-synchronised replacement reserve, which is the predominant service offered offered by the BNE, compared to the rate consulted upon earlier in the year[8].

With regards to the Interim Tariff arrangements not offering any payments for 'Fast Frequency Response' (FRR), 'Dynamic Reactive Response' (DRR) and Fast Post Fault Active Power Recovery (FPFAPR), the SEMC agrees with the consideration of the respondents that there are to be no monies earned through those services as they have not been included in the Interim Tariff arrangements for 2016-17.

The model estimates for the Ancillary Services deduction has been recalculated to omit any revenues earned from the DRR, FRR and FPFAPR services as there will be no procurement of those services during the interim period, and a revised figure is included in the final decision.

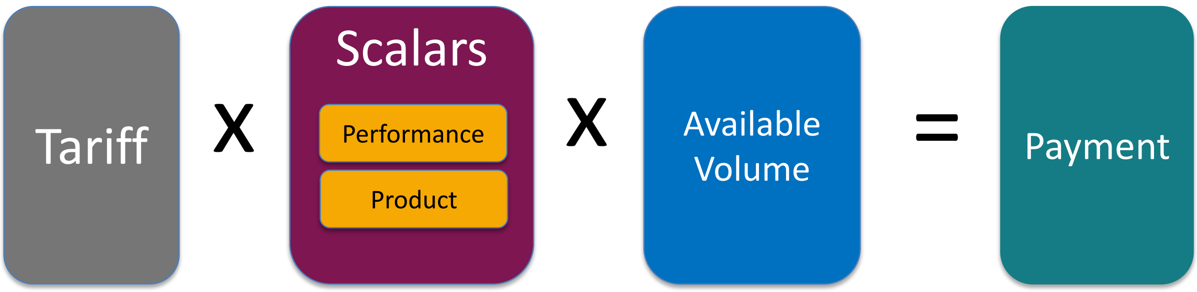
For the purposes of calculating the Interim DS3 Tariffs the TSOs have assumed that the performance scalar of each unit shall be equal to 1.0, the rationale for this is set out in §3.3 of the *DS3 System Services Interim Tariffs Decision Paper - DS3 System Services*

[8] Appendix 3 contains the new tariff rates. The rate for de-synchronised RR has reduced from €0.62/MW to €0.5/MW.

Implementation Project[9]. The SEM Committee considers that a performance scalar of 1.0 would be reasonable for a BNE peaker, given the settings for data poor plant under the Interim Tariff arrangements. It should be noted that the decision on Interim Tariffs only applies from October 2016 to September 2017 and that the performance scalar arrangements under DS3 may be subject to review as part of the development of the enduring arrangements.

In refining the DS3 Revenue deduction model the SEM Committee has made an allowance for one trip charge in every four years of operation and an annual availability for payment of 90.17%. These refinements in isolation increase the assumed net revenue from System Services by around €0.09/kW compared to the consultation calculation, which assumed one trip every year.

The application of the performance scalar in calculating the tariff rates is set out in §4.3 of the decision paper on Interim Tariffs and is summarised as follows:



Appendix 3 Revenues earned by Alstom GT13E2 and Respective Volumes including a breakdown of modelled revenues earned by the BNE in respect of the new DS3 System Services rates.

[9] DS3 System Services Interim Tariff Rates http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Services-Interim-Tariffs-FINAL.pdf

In response to points regarding the 2014 Procurement Decision Paper which states that the generators will be paid irrespective of constraints on the better of Market or Dispatch position, the RAs assume that the BNE is not dispatched beyond market outcomes.

In response to the capability of the BNE in relation to revenues earned though the DS3 service 'Replacement Reserve – Synchronised' (RRS), the RAs agree with this point and therefore recalculated the estimate of this revenue stream for 2017. The reduction of the Alstom GT13E2's capability under this service to 78.28 MW, has an overall 2-3c/kW reduction on the deduction for Ancillary Services.

The RAs have calculated the Ancillary Services deduction using the DS3 revenues model considered at the consultation phase. The objection to using a DS3 deduction at all, and the preference of two respondents to indexing the HAS figure from 2016 is not considered appropriate as the Ancillary Services revenues for DS3 has replaced HAS.

The Interim Tariff rates have been amended for the changes seen in the DS3 interim tariff rates decision paper approved at the SEM Committee in July 2016. The changes to these rates, along with the removal of the three services that would not offer any volumes under the trial process reduces the DS3 deduction to 7.34 €/kW/Yr.

Inframarginal Rent

The methodology used for the deduction of infra-marginal rent was not consulted upon and the SEM Committee do not intend to change this at this time. As a result of the CPM Medium Term Review, the methodology for calculating the infra-marginal rent was changed. Infra-marginal rent is deducted from the BNE using the following formula:

*Deduction for Infra-marginal rent (€/kW) = [(PCAP – BID)/1000] * OUTAGE TIME * (1 – FOP)*

The RAs calculated the average bid price (in Euro) of all existing distillate units in the SEM on 21 June 2016 (the same date as was taken for other parameters such as exchange rate and commodity prices) 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:

Item	Value
Price Cap (€/MWh)	1000
Outage Time (Hours)	8
BID Price of Peaker (€/MWh)	164.56
FOP	5.91%

Table 5.1 – IMR Deduction Calculation Parameters

The formula for the IMR deduction above gives a final figure of €6.29/kW on an annualised basis.

Capacity Requirement and Generation Security Standard

In relation to the Capacity Requirement calculations, the methodology uses a simulated program ("**AdCal**") which takes into account the weighted capacity of wind and historical scheduled outages programs as well as market load in order to calculate a forecasted capacity requirement, whereas the calculation within the Generation Capacity Statement takes into account all generators on the system to meet the total electricity requirement, and hence are not directly comparable.

Following the CPM methodology for calculating the Capacity Requirement, and in consultation with the Regulatory Authorities, the TSOs have used the 2014 demand shape and the 2014 wind shape in its modelling. The forecast TER used was the median demand from the recently published Generation Capacity Statement 2016-25.

The 2017 Capacity Requirement was calculated to be approximately 7267 MW. As can be seen in the graph below, the changes in the Capacity Requirement and the SEM peak[10] over recent years are graphed against the margin of Capacity Requirement over the SEM peak. A margin over the peak of approximately 9%, (similar to previous years) can be seen.

The methodology has, by its nature, the potential to produce variations. While it can be seen that there are variations from year to year, these variations are small in comparison with the size of the Capacity Requirement.

[10] The SEM peaks are derived by subtracting the non-market load from the total All-Island load based on an estimation of the contribution from non-market units (wind and non-wind)

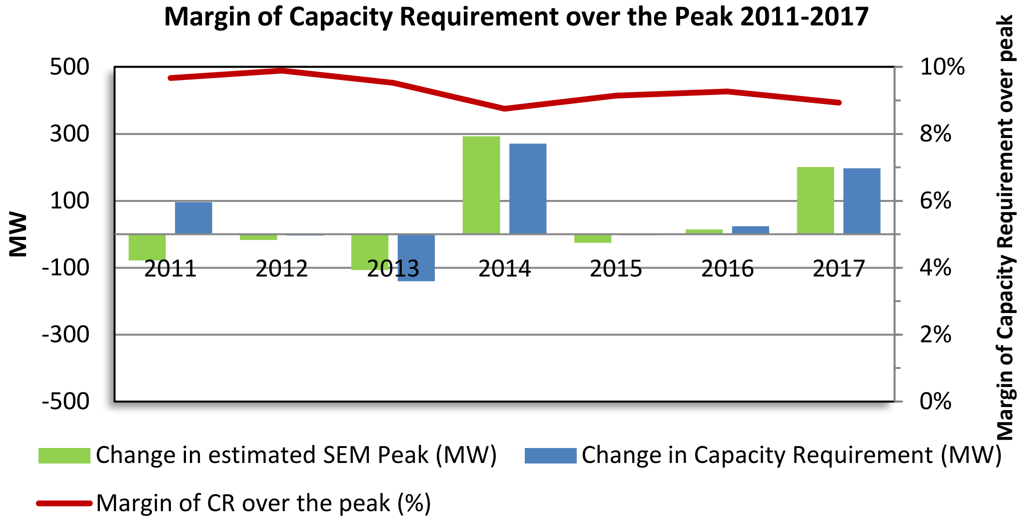


Figure 5.2 – Margin of capacity Requirement over the Peak

While noting various other comments received, the RAs consider that these comments largely fall out of the scope of this process and were addressed previously within the CPM Medium Term Review decision (SEM-12-016).

As the consultation paper for the 2017 Annual Capacity Payment Sum did not consult on the GSS, the SEM Committee are keen to stress that this figure will remain in the determination of the fixed costs of running a BNE in the SEM.

6 ANNUAL CAPACITY PAYMENT SUM FOR 2017

6.1 FIXED COST OF A BNE PEAKING PLANT AND CAPACITY REQUIREMENT

Having considered the responses to the consultation, along with other relevant information available, the RAs have updated the final BNE figure to account for the following:

- RPI data for June 2016[11] shows an average price increase of 1.6%. The figures ‘Consultation 2017’ and ‘Decision 2017’ have been calculated by indexing the 2016 annualised cost by 1.4% (May 2016 RPI) and 1.6% (June 2016) respectively.

- A deduction based on DS3 services using the Final Decision Interim Tariffs

[11] RPI figures available at http://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/czbh

- Application of the infra-marginal rent deduction formula as follows:

IMR deduction (€/kW) = [(PCAP – BID)/1000] * OUTAGE TIME * (1 – FOP)
= [1000 – **164.56**)/1000] * 8 * (1 - 5.91%)
= €6.29/kW

Note that only the bid price element has been adjusted within this calculation. The bid price calculated above is based on the average bids of distillate fired plants from Within Day data from the Single Electricity Market Operator (SEMO) on 21 June 2016.

The Capacity Requirement is to remain as per proposed in the Consultation Paper at 7267 MW. The BNE Peaker Cost and Capacity Requirement will therefore be as follows.

	Decision 2016	Consultation 2017	Decision 2017
Annualised Cost per kW per year	83.74	84.91	85.08
Ancillary Services	4.64	N/A	N/A
DS3 Deduction	N/A	7.67	7.34
Inframarginal Rent	6.28	6.42	6.29
BNE Cost per kW per year	**72.82**	**70.99**	**71.45**
Capacity Requirement (MW)	**7070**	**7267**	**7267**
Annual Capacity Payment Sum	**€514,837,400**	**€515,884,330**	**€519,227,150**

Table 6.1 BNE and Capacity Requirement Decision for Trading Year 2017

The Annual Capacity Payment Sum (ACPS) for 2017 is €519,227,150

6.2 FCPPy AND ECPPy FOR 2017

Following receipt of responses, the RAs have decided not to amend the Fixed Capacity Payment Proportion and Ex-Post Capacity Payment Proportion for 2017.

$$\mathbf{ECPP}_{y} = \mathbf{0.3}$$
$$\mathbf{FCPP}_{y} = \mathbf{0.3}$$
$$\boldsymbol{VCPP}_{y} = \mathbf{0.4}$$

7 APPENDIX 1 - ANNUAL CAPACITY PAYMENT SUM FOR PREVIOUS TRADING YEARS

The annualised fixed cost of the BNE Peaker is multiplied by Capacity Requirement resulting in the Annual Capacity Payments Sum (ACPS). The ACPS for all previous years are detailed in Table A1.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2007	64.73	6,960	450,517,348
2008	79.77	7,211	575,221,470
2009	87.12	7,356	640,854,720
2010	80.74	6,826	551,133,375
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
2016	72.82	7,070	514,837,400
2017	71.45	7,267	519,227,150

Table A1.1 – ACPS for Previous Trading Years

8 APPENDIX 2- DEMAND FORECAST

Med	TER (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2015	27,425	2.4%	9,058	0.1%	36,483	1.8%	5043	1752	6746	4945	1733	6631
2016	27,989	2.1%	9,097	0.4%	37,086	1.7%	5092	1761	6805	4994	1741	6687
2017	28,899	3.3%	9,139	0.5%	38,038	2.6%	5167	1769	6888	5070	1747	6769
2018	29,566	2.3%	9,178	0.4%	38,745	1.9%	5209	1777	6938	5112	1753	6818
2019	30,159	2.0%	9,216	0.4%	39,375	1.6%	5243	1785	6980	5146	1761	6858
2020	30,681	1.7%	9,255	0.4%	39,935	1.4%	5294	1792	7038	5196	1767	6916
2021	31,238	1.8%	9,297	0.5%	40,535	1.5%	5338	1799	7089	5241	1773	6966
2022	31,788	1.8%	9,337	0.4%	41,125	1.5%	5416	1807	7174	5319	1780	7051
2023	32,365	1.8%	9,381	0.5%	41,746	1.5%	5498	1815	7264	5400	1787	7140
2024	32,934	1.8%	9,420	0.4%	42,354	1.5%	5578	1823	7354	5481	1795	7229
2025	33,480	1.7%	9,463	0.5%	42,943	1.4%	5655	1832	7439	5558	1803	7313

TableA2-1: Median Demand Forecast

9 APPENDIX 3 REVENUES EARNED BY ALSTOM GT13E2 AND RESPECTIVE VOLUMES

Service Name	Abbreviation	Capability (MW)	Units of Service provided	Rates (€/MW)	Revenues (€)
Synchronous Inertial Response	SIR	2479.5	434,408	0.0046	1,998
Fast Frequency Response	FFR	10.6	1,857	2.06	3,826
Primary Operating Reserve	POR	21.2	3,714	2.93	10,883
Secondary Operating Reserve	SOR	35.4	6,202	1.78	11,040
Tertiary Operating Reserve 1	TOR1	35.4	6,202	1.41	8,745
Tertiary Operating Reserve 2	TOR2	35.4	6,202	1.12	6,946
Replacement Reserve - Synchronised	RRS	78.28	34,287	0.23	3,154
Replacement Reserve - Desynchronised	RRD	195.7	1,545,813	0.5	772,907
Ramping Margin 1	RM1	78.28	13,715	0.1	1,371
		195.7	1,545,813	0.1	154,581
Ramping Margin 3	RM3	78.28	13,715	0.16	2,194
		195.7	1,545,813	0.16	247,330
Ramping Margin 8	RM8	78.28	13,715	0.14	1,920
		195.7	1,545,813	0.14	216,414
Fast Post Fault Active Power Recovery	FPFAPR	117.42	-	0.14	-
Steady State Reactive Power	SSRP	212	-	0.21	-
Dynamic Reactive Response	DRR	195.7	-	0.04	-
Trip charge (1 trip in every four years of operation)	TRIP	-	-	-	-6149.25

Table A3.1 – Revenues Earned under DS3 System Services Interim Tariffs