Single Electricity Market

Capacity Requirement and Annual Capacity Payment Sum for Calendar Year 2015

Decision Paper

5 August 2014

SEM-14-070

1 EXECUTIVE SUMMARY

The Capacity Payment Mechanism is a fixed revenue mechanism which collects a pre-determined amount of money from suppliers, and pays these funds 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 – 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 is an 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 2013. In accordance with the decision described in the CPM Medium Term Review Final Decision Paper (SEM-12-016)[1], its costs have been fixed and indexed for three years.

The annualised fixed cost, net of estimated Infra-Marginal Rent and Ancillary Services revenue determined for the 2014 ACPS was €80.27/kW/year. When this is adjusted for inflation and infra-marginal rent and ancillary services deducted, the annualised fixed cost for 2015 is €81.60/kW/year.

The Capacity Requirement for 2015, calculated using a similar methodology to previous years, is 7,046MW.

The product of these price and quantity elements yields an Annual Capacity Payment Sum for 2015 of €574,953,600.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2015	€81.60	7,046MW	€574,953,600

This compares to an ACPS of €565,819,301 for the 2014 capacity year (an increase of 1.6%).

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

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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. It pays this money to available generation capacity in accordance with rules set out in the SEM Trading and Settlement Code ("**TSC**")[2]. 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[3]. 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[4] 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.

[2] http://www.sem-o.com/MarketDevelopment/Pages/MarketRules.aspx
[3] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?page=2&article=0e5940cb-4c5d-4e01-982d-2b3587c33d2d
[4] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?page=2&article=94ef0599-001a-4923-a706-7682f76ec79b

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 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)[5]. 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. In the paper, the SEM Committee 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 SEM Committee published the final decision paper on the CPM Medium Term Review (SEM-12-016)[6].

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

[6] http://www.allislandproject.org/en/cp_decision_documents.aspx?page=1&article=5ce2db5f-6c79-4454-9779-53dd7fae8dba

4 CONSULTATION

On 28 April 2014, the RAs published a consultation paper on the *'Capacity Requirement and Annual Capacity Payment Sum for Calendar Year 2015'* (SEM-14-033)[7].

4.1 BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2015

In the decision paper on the Fixed Cost of a BNE peaking plant, Capacity Requirement and Annual Capacity Payment Sum for the Calendar Year 2013[8], the BNE for 2013 and the following two years was determined as an Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland.

The table below provides a summary of the final annualised cost of the BNE Peaker for 2013 and 2014. This includes the deduction of any revenues obtained from Infra Marginal Rent or Ancillary Services.

Because the BNE is located in Northern Ireland, the CPI as measured in the UK will be used to index the BNE annualised cost.

At the time of the consultation, the most recent inflation data available for CPI in the UK showed that average prices in the UK increased by 1.76% between February 2013 and February 2014. The annualised BNE cost to be used in the 2015 Annual Capacity Payment Sum was therefore calculated to be €81.75/kW/year.

	Decision 2013	Decision 2014	Proposed 2015
Annualised Cost per kW per year	88.14	90.51	92.10
Ancillary Services	4.37	4.46	4.55
Infra-Marginal Rent	5.59	5.78	5.80
BNE Cost per kW per year	**78.18**	**80.27**	**81.75**

4.2 CAPACITY REQUIREMENT FOR 2015

The methodology used for calculating the Capacity Requirement for 2015 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 2015 should be **7,046MW**. This represents a decrease of 3MW from the Capacity Requirement for 2014.

[7] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=ca2b1d5f-f11b-4bc0-842d-05c1864ad495

[8] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=75c548a7-34ee-497c-afd2-62f8aa0062df

4.3 FCPPy AND ECPPy FOR 2015

The Fixed Capacity Payments Proportion (FCPPy) 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 (ECPPy) 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 (VCPPy) is implicitly derived from the values of FCPPy and ECPPy. This is set such that:

$$VCPPy = (1 – FCPP – ECPP)$$

The VCPP 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:

$$ECPPy = 0.3$$
$$FCPPy = 0.3$$
$$VCPPy = 0.4$$

Within the consultation, the RAs did not propose changing the payment proportions for 2015.

5 CONSULTATION RESPONSES

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

- Bord na Móna PowerGen
- Energia
- Power NI Energy Ltd Power Procurement Business (PPB)

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

5.1 SUMMARY OF COMMENTS RECEIVED

Rolling forward the BNE peaking plant cost for 2015

The consultation paper proposes to apply 2% inflation to the Harmonised Ancillary Service revenues and Other System Charges. **PPB** and **Energia** highlighted that this does not reflect the proposed increase for these revenues and charges of 1.5% in the 2 April 2014 consultations on these rates.

BnM recognise that the indexation for ancillary services is being calculated on the same basis as applicable in the latest Harmonised Ancillary Services and Other System Charges decision paper at a rate of 2%.

The Capacity Requirement for 2015

PPB believe it is surprising that the peak demand used in the assessment had decreased from 2014.

While the peak demand forecast is based on the TSOs' most recent capacity statement for 2014-2023, there has been no consultation on the assumptions contained in the TSOs' forecasts. These result in a reduction in peak demand at the same time as the Total Energy Requirement is increasing, thereby resulting in an increased Annual Load Factor (ALF).

Furthermore, there is little rationale for the reduction and indeed the reduction contradicts the commentary that is included within the document.

Energia – the consultation paper provides insufficient information to support the analysis that Capacity Requirement has fallen and the RAs should review this and update the Capacity Requirement based upon this review and more up-to-date information.

Annualised BNE Cost

Using a CPI index measured in the UK does not reflect the risk / reality of investing and operating in the single all-island market. **Bord na Móna** believes the use of a blended NI-ROI indexation is more appropriate.

Forced Outage Probability (FOP)

It is **Bord na Móna's** opinion that the Forced Outage Probability should be based on the actual forced outage rates (moving average) seen in the market rather than an 'aspirational' target that has not been achieved in any of the previous 3 years.

Inframarginal Rent Deduction

Bord na Móna acknowledges that the methodology used in calculating the ACPS is not open for deliberation in this consultation. However, it would be remiss of this organisation not to highlight the 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.

FCPPy and ECPPy

Bord na Móna sees no objective evidence at this moment in time to change the weighting of these factors.

5.2 RESPONSES TO COMMENTS RECEIVED

Load Forecast

PPB believed it was surprising that the peak demand had decreased from 2014, while **Energia** considered that the consultation paper provides insufficient evidence to support to analysis that the Capacity Requirement has fallen.

The load forecast made in the current Generation Capacity Statement 2014-23 (GCS14), as used for the 2015 Capacity Requirement, is lower than that made for the previous GCS13, when comparing year to year (cf. Figures 2-7 and 2-8 in GCS 2014-23). This is due to a slightly lower outcome in 2012 than what had been forecasted, the use of updated economic forecasts, and also due to more rigorous measures for energy efficiency being employed in the GCS14 forecast, incorporating the effect of smart meters.

The current GCS14 demand forecast is still increasing year on year, but at a slightly slower rate than that used for the previous GCS (2013-22). Thus, the forecasts for energy and peak in GCS14 are below those for GCS13.

The small discrepancy between the 6,666 MW quoted in the consultation paper for the peak used in the 2014 Capacity Requirement and the 6,676 MW quoted as the TER peak in the GCS13 arises out of the slight differences in totalling the small-scale-generator contribution in Northern Ireland. 10 MW of demand met by non-market non-wind generation was taken away from the TER peak of 6,676 MW as quoted in the GCS13. In the calculations for the Capacity Requirement, all non-market load and generation are omitted from the adequacy study, and so the methodology is consistent year after year.

Impact of WPDRS cessation, and the Annual Load Factor

PPB raised the point that the Annual Load Factor should be increasing. The extra portion added to the peak due to the cessation of the WPDRS (Winter Peak Demand Reduction Scheme) was first done for the peaks starting in winter 2013/14 in GCS 2013-22, and which

was used for the Capacity Requirement calculation for 2014 (CR2014). This was a one-off, step increase, and its effect was felt from the 2013 winter peak forecast onwards. The peak forecast used for the CR2015 continues to assume the same 60 MW increase over and above what would be expected if WPDRS was still included, and therefore could be said to be already included, i.e. there is no relative increase between the peak used for CR2014 to that used for CR2015 due to the WPDRS effect.

The Annual Load Factor is used in determining the peak forecast from the energy forecast. In Ireland, the ALF has actually been rising gradually in the past ten years, and is expected to rise further in the coming years due to the influence of smart meters. The ALF relationship is used *before* any adjustment for WPDRS (or other demand side measure in the past).

Deduction for Ancillary Services

PPB and **Energia** raised the point that the consultation paper did not properly account for the proposed inflation rate for Harmonised Ancillary Services. The deduction for Ancillary Services will be amended to account for the 1.5% inflation in Harmonised Ancillary Service revenues as described in the Decision Paper published on 30 July 2014[9].

Forced Outage Probability Indexation and Inframarginal Rent

Bord na Mona stated that the Forced Outage Probability should be based on actual forced outage rates, that the indexation should be a blended NI-ROI indexation and that there exists a 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

The Indexation, the Forced Outage Probability and the methodology used for the deduction of infra-marginal rent were not consulted upon and are not subject to change at this time.

FCPPy and ECPPy

[9] SEM-14-069

The Fixed Capacity Payment Proportion and Ex-Post Capacity Payment Proportion are not being changed at this time.

6 ANNUAL CAPACITY PAYMENT SUM DECISION 2015

6.1 BNE 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:

- CPI data for May 2014[10] showed that average prices in the UK increased by 1.51% between May 2013 and May 2014;
- Indexation of Ancillary Services by 1.5%
- Application of the infra-marginal rent deduction formula as follows:

IMR DEDUCTION IN €/kW = [(PCAP – BID)/1000] * OUTAGE TIME * (1 – FOP)
= [1000 – 236.48)/1000] * 8 * (1 - 5.91%)
= €5.75/kW

Note that only the bid price element has been adjusted within this calculation. The bid price calculated above is based on the average distillate bids (WD1) on 1 July 2014.

The Capacity Requirement is to remain as per proposed in the Consultation Paper at 7,046MW. The BNE Peaker Cost and Capacity Requirement will therefore be as follows.

	Decision 2014	Proposed 2015	Decision 2015
Annualised Cost per kW per year	90.51	92.10	91.88
Ancillary Services	4.46	4.55	4.53
Inframarginal Rent	5.78	5.80	5.75
BNE Cost per kW per year	**€80.27**	**€81.75**	**€81.60**
Capacity Requirement (MW)	**7,049**	**7,046**	**7,046**
Annual Capacity Payment Sum	**€565.82m**	**€576.01m**	**€574.95m**

Table 6.1 BNE and Capacity Requirement Decision for Trading Year 2015

The Annual Capacity Payments Sum (ACPS) for 2015 is €574.95m

[10] http://www.ons.gov.uk/ons/taxonomy/index.html?nscl=Consumer+Prices+Index#tab-data-tables

6.2 FCPPy AND ECPPy FOR 2015

Following receipt of responses, the RAs have decided not to amend the Fixed Capacity Payment Proportion (FCPPy) and Ex-Post Capacity Payment Proportion (ECPPy) for 2015.

The payment proportions for 2015 are therefore:

FCPPy for 2015 = 0.3

ECPPy for 2015 = 0.3

The VCPP is thus retained as:

VCPPy for 2015 = 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

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
2014	26,601	1.0%	9144	0.6%	35,745	0.9%	4871	1766	6608	4774	1728	6473
2015	26,910	1.2%	9205	0.7%	36,115	1.0%	4903	1773	6647	4806	1733	6510
2016	27,280	1.4%	9269	0.7%	36,550	1.2%	4958	1781	6710	4861	1739	6571
2017	27,687	1.5%	9334	0.7%	37,021	1.3%	5009	1790	6769	4911	1746	6628
2018	28,078	1.4%	9399	0.7%	37,477	1.2%	5068	1800	6838	4971	1755	6696
2019	28,471	1.4%	9465	0.7%	37,936	1.2%	5127	1810	6907	5030	1764	6765
2020	28,945	1.7%	9535	0.7%	38,480	1.4%	5201	1822	6993	5104	1775	6849
2021	29,337	1.4%	9603	0.7%	38,940	1.2%	5266	1834	7069	5169	1786	6925
2022	29,734	1.4%	9672	0.7%	39,407	1.2%	5333	1845	7147	5236	1797	7002
2023	30,130	1.3%	9743	0.7%	39,873	1.2%	5399	1857	7226	5301	1808	7078

TableA2-1: Median Demand Forecast