Single Electricity Market

Capacity Requirement and

Annual Capacity Payment Sum

for Calendar Year 2015

Consultation Paper

28 April 2014

SEM-14-033

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 (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 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 €81.75/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 €576,011,918.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2015	81.75	7,046MW	€576,011,918

This compares to an ACPS of €565,819,301 for the 2014 capacity year.

[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 and pays these funds 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 due to the annual determination of the Best New Entrant Fixed Cost. 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 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[7], 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.

When determining this calculation 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[8]. The proposed annualised BNE cost per kW to be used in the 2015 Annual Capacity Payment Sum is therefore €92.10/kW/year. This will be re-calculated prior to decision to account for inflation between May 2013 and May 2014.

In the decision paper for the 2014 Annual Capacity Payment Sum, the deduction to reflect ancillary services revenue earned by the BNE was increased by 2%. The RAs recognised that for consistency, indexation should be applied on the same basis as per the latest Harmonised Ancillary Services and Other System Charges decision paper. The RAs propose to retain this 2% indexation for Ancillary Services. The deduction for ancillary service revenue in 2015 is therefore €4.55/kW/year.

A deduction for infra-marginal rent also needs to be made. As per the decision on deduction of Infra-Marginal Rent in the CPM Medium Term Review Decision Paper, this deduction will be calculated using the following formula:

$$\text{IMR DEDUCTION IN €/kW} = [(\text{PCAP-BID}) / 1000] * \text{OUTAGE TIME}*(1\text{-FOP})$$

The only element of this that changes from year to year is the average bid price of a distillate unit in the SEM. For indicative purposes, the deduction for infra-marginal rent has been calculated according to generator commercial offer data on 12 April 2014. This will be re-calculated post-consultation.

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

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

	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**

5 CAPACITY REQUIREMENT FOR 2015

5.1 INTRODUCTION

The methodology used for calculating the Capacity Requirement for 2015 is the same as used in previous years' calculations. This section details the individual components and calculations that have been carried out for the quantification of the 2015 Capacity Requirement.

As in previous years the RAs may revisit the demand forecasts with the TSOs for the decision process if they believe there is any need to change the forecasts based on the most up to date information.

5.2 BACKGROUND TO CALCULATION OF CAPACITY REQUIREMENT PROCESS

The Capacity Requirement quantification process was consulted on in August 2006 under 'Methodology for the Determination of the Capacity Requirement for the Capacity Payment Mechanism' (AIP/SEM/111/06). This was a comprehensive consultation which took place following an initial consultation on the CPM in March 2006 entitled 'The Capacity Payment Mechanism and Associated Input Parameters' (AIP/SEM/15/06).

A Decision Paper was published in February 2007 which set out the RAs' decisions on the contents of the August 2006 Consultation Paper. This Decision Paper described the key methodology and individual data point assumptions. These parameters were used in calculating all previous Capacity Requirements.

5.3 PARAMETER SETTINGS FOR CAPACITY REQUIREMENT FOR 2015

The following sections describe further each of these parameter settings used in the calculation of the 2015 Capacity Requirement.

5.3.1 GENERATION SECURITY STANDARD (GSS)

In AIP/SEM/111/06 the RAs stated that a single GSS for the entire island would be applied following detailed research by the TSOs in March 2007. This research was presented to the AIP Steering Group in May 2007 and the RAs subsequently decided on a GSS of 8 hours loss of load expectation per annum. The GSS of 8 hours has been retained by RAs for the 2015 calculation.

5.3.2 DEMAND FORECAST

For the purposes of calculating the Capacity Requirement, the demand forecast was taken from the median scenario of the Eirgrid / SONI forecast in Appendix 1 of the 2014-2023 All-Island Generation Capacity Statement[9]. This forecast is stated in terms of the Total Energy Requirement (total energy exported from generating units, plus self-consumption).

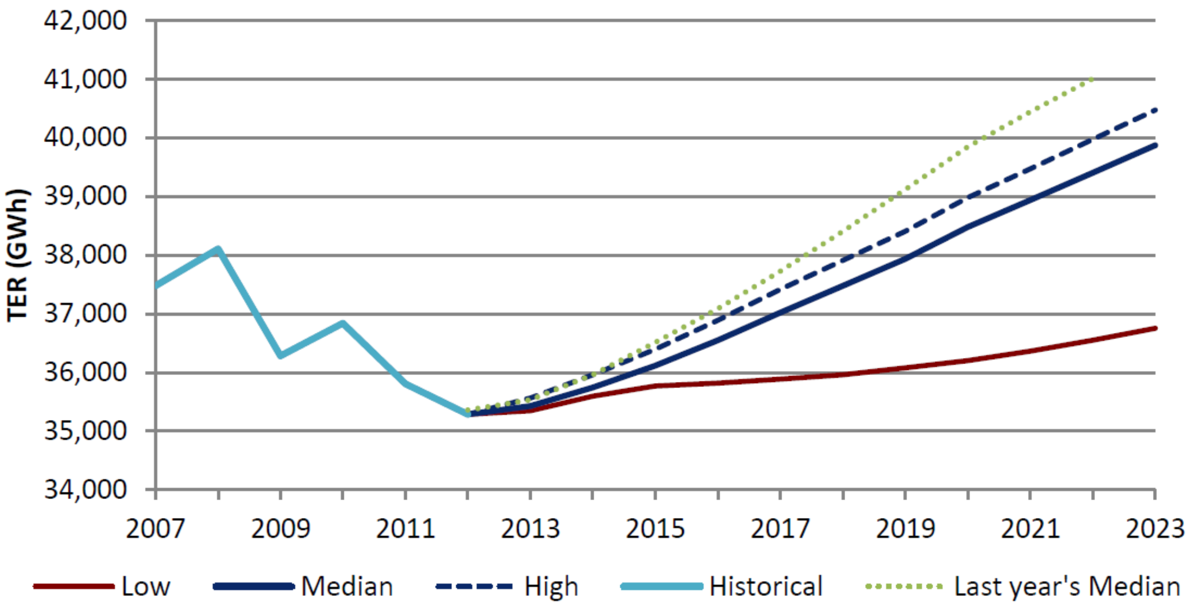

Figure 5.1 All-Island Demand Forecast [10]

The Demand forecast not only takes into account economic conditions but also looks at historical annual load shape and typical weather patterns.

For the 2015 Capacity Requirement calculation, the TSOs were asked to provide half-hourly demand forecast profiles. Care was exercised to ensure that the jurisdictional traces were harmonised and aligned on a day-by-day basis. The RAs assisted in combining these jurisdictional load traces into a single, all-island demand trace for input to the ADCAL calculation engine (described below).

The forecasted demand, used in the Capacity Requirement Calculation for each jurisdiction was as follows:

[9] http://www.soni.ltd.uk/media/documents/News/Generation%20Capacity%20Statement%202014-2023.pdf

[10] Chart based on Figure 2-7, Page 22 , All-island Generation Capacity Statement 2014-23

	2015 Forecasted Total Energy Requirement
Republic of Ireland	26,910
Northern Ireland	9,205
All-Island	36,115

Table 5.1 – *Demand Forecast*

While changes in total energy requirement will have an effect on the changes to the Capacity Requirement, of greater impact will be the changes in the peak demand.

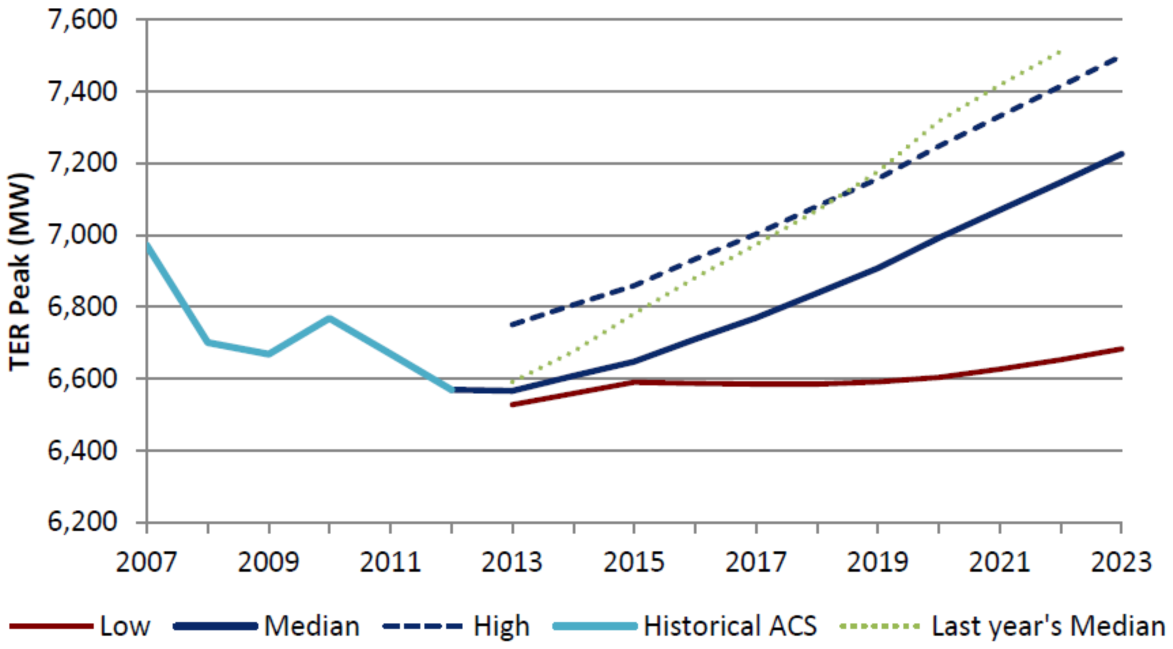

Figure 5.2 All-Island Peak Demand Forecast

Forecasted peak demand has decreased by 19MW from the forecast used for the 2014 Capacity Requirement (6,666MW) to the forecast used for the 2015 Capacity Requirement (6,647MW).

5.3.3 GENERATION CAPACITY

The generation capacity is based on the Generation Plant Information within Appendix 2 of the All-Island Generation Capacity Statement 2014-2023. This was cross-checked against the 2013-14 Validated SEM Generator Data Parameters, collected by the RAs as part of the Directed Contracts process. The capacities of units which are expected to enter/exit the market in 2015 were time-weighted to reflect their expected entry/exit date.

5.3.4 SCHEDULED OUTAGES

In the Decision Paper AIP/SEM/07/13 it was decided that scheduled outages for thermal plant would be quantified based on the previous five years of unit set data, and that the ADCAL algorithm would be permitted to efficiently schedule these outages during the calendar year. This process has continued to be applied in formulating the scheduled outage inputs for each unit in the 2015 Capacity Requirement process.

5.3.5 FORCED OUTAGE PROBABILITIES

The Decision Paper AIP/SEM/07/13 set out the RAs' decision to set a target for Forced Outage Probabilities ("**FOP**") to incentivise an improvement in plant performance above the historical levels. This value was calculated based on the observed improvements in plant performance following privatisation of the Northern Ireland portfolio in the 1990s and was computed at 4.23%. The Decision Paper (AIP/SEM/07/13) clarifies that the computed value was to be used in calculations going forward.

As described in the Decision Paper on the CPM Medium Term Review, the SEM Committee decided to amend the FOP to 5.91% for the 2013 and future Annual Capacity Payment Sum calculations.

5.3.6 TREATMENT OF WIND

The Decision Paper AIP/SEM/07/13 explains the RAs' decision to treat wind as a netting trace against the load trace. This process has been repeated in the 2015 process. Individual wind output traces were provided by the TSOs. The wind traces are aligned on a day-by-day basis with the load traces described earlier.

5.3.7 ADCAL CALCULATION PROCESS

Having collected together the various input data points, the TSOs ran the iterative ADCAL software process to calculate the 2015 Capacity Requirement.

The ADCAL process has been described in AIP/SEM/111/06 and the subsequent decision to employ a 'perfect plant' method detailed in the Decision Paper AIP/SEM/07/13. The process is discussed in more detail below.

Once the input data has been assembled, the Capacity Requirement quantification process involves the following steps:

1. Use ADCAL to calculate the Loss of Load Expectation (LOLE) for 2015 that arises from the conventional market capacity, employed to meet the 2015 load trace with wind output netted from this trace.

2. Assuming this LOLE is below the target of 8 hours, add incremental block loads (‘perfect plant’) to the load trace and recalculate the LOLE.

3. Repeat Step 2 until the LOLE is exactly 8 hours for the year.

4. Note the quantity of block load used to obtain the 8 hour LOLE (referred to as BLOAD).

5. If in surplus, build a 'reference plant' with statistics based on the stack of generators (averaged capacity, SOD etc.).

6. Add this plant to the stack and use ADCAL to re-calculate LOLE, the LOLE will again decrease below the 8 hour mark.

7. Add some additional block load until the 8 hours is once again achieved. Note the amount of additional block load used in this step above the original BLOAD.

8. Divide the Capacity of the Reference plant by calculated in step 7 above. This represents the ratio of imperfect-to-perfect plant.

9. Multiply the ratio in step 8 by the original perfect surplus in step 4. This is the imperfect surplus.

10. Deduct the imperfect surplus from the total installed capacity used in Step 1, this is the conventional requirement.

11. Calculate the all-island Wind Capacity Credit based on the credit curve methodology used in the Generation Adequacy Report and the assumed installed capacity of Wind on the island.

12. Add the Wind Capacity Credit to the Step 10 conventional requirement; this is the final Capacity Requirement.

5.4 PROPOSED CAPACITY REQUIREMENT FOR 2015

The inputs used in the 2015 consultation calculations are summarised below. The associated data sets are attached as appendices to this paper.

Input	Description
Load Forecasts for ROI and NI for 2015	A combined load forecast for 2015, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. Two traces were agreed: 1) Total Load Forecast for 2015 2) Total (In Market) Conventional Load Forecast 2015 See Appendix 3 – Load Forecast for 2015
Generation Capacity	A list of all generation to be in place in 2014 was determined, including the Sent Out Capacity for each unit. For any units to be commissioned or decommissioned during 2015, the Capacity available was adjusted accordingly to reflect the actual period they are available (time weighted average). The Time-Weighted Capacity for Conventional Generation used in the Adcal model was **10,031MW** See Appendix 4 – Generation Capacity for 2015
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 2015 used was **3,258MW**. This results in a Capacity Credit of 0.137. The Time Weighted Market Wind Capacity in 2015 was **2,700MW**. Therefore the Wind Capacity Credit is derived as **369MW** (2,700 * 0.137) See Appendix 5 – Wind Capacity in 2015
Scheduled Outages	The Scheduled Outage Durations are determined to the nearest number of weeks and are determined from the five-year average of scheduled outages for each unit.

	See Appendix 6 – Average SOD for 2015
Force Outage Probability (FOP)	In line with the SEM Committee decision on the CPM Medium Term Review, the FOP has been set at **5.91%**.
Generation Security Standard (GSS)	The RAs maintained the value of **8 hours** for the GSS.

Table 5.2 – *Summary of Inputs into Adcal Model*

As a result of the analysis carried out in conjunction with the TSOs, the RAs have determined that the Capacity Requirement for 2015 is **7,046MW.** This is a decrease of 3MW from the Capacity Requirement for 2014 of 7,049MW.

The Proposed Capacity Requirement for 2015 is 7,046MW

6 INDICATIVE ANNUAL CAPACITY PAYMENT SUM FOR 2015

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement for 2015 as detailed above, the Annual Capacity Payments Sum (ACPS) for 2015 is proposed to be €576.01m. The proposed figures are detailed in table 6.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2015	81.75	7,046MW	€576,011,918

Table 6.1 – ACPS for the Trading Year 2015

The Proposed Annual Capacity Payments Sum (ACPS) for 2015 is €576.01m

7 FCPPy AND ECPPy FOR 2015

7.1 INTRODUCTION

The SEM Trading and Settlement Code requires the RAs to determine on an annual basis values for certain parameters in relation to the calculation of Capacity Payments and Capacity Charges for the following year. These parameters include:

- Fixed Capacity Payments Proportion (FCPPy), such that 0 ≤ FCPPy ≤1;
- Ex-Post Capacity Payments Proportion (ECPPy), such that 0 ≤ ECCPy ≤ (1-FCPPy)

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:

$$\text{VCPPy} = (1 - \text{FCPPy} - \text{ECPPy})$$

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:

$$\text{FCPPy} = 0.3$$
$$\text{ECPPy} = 0.3$$
$$\text{VCPPy} = 0.4$$

7.2 TSO REPORT AND PREVIOUS CONSULTATION

Before the RAs consulted on these values for 2014, they asked the Transmission System Operators (**TSOs**) (SONI (in Northern Ireland) and Eirgrid (in Republic of Ireland)) to produce a report on the effectiveness of the current payment proportions and the potential impact any changes to these proportions might have. That report made a number of points, including:

- For some Interconnector Users there is some positive correlation between forecast demand and their interconnector nominations, i.e. they import less at times of low demand.
- However the remaining Interconnector Users show no correlation with any of the market parameters listed above.
- An analysis of the Ex-post capacity payments showed that payments are low at times of high wind generation in the SEM. This is because wind generation is an input to the outturn Loss of Load Probability calculation, i.e. there is unlikely to be a shortage of generation at times of high wind generation.
- Ex-post capacity payments are also low at times of low demand in the SEM. Demand is an input to the Loss of Load Probability calculation, i.e. there is unlikely to be a shortage of generation at time of low demand.
- High Ex-post capacity payments occurred at times of high demand and low generation margins, which is providing the correct market signal to reward generation when it is needed.

After considering the responses to the consultation, the RAs determined to retain the existing settings (i.e. FCPP = 0.3, ECPP = 0.3 and VCPP = 0.4) for Trading Year 2014.

7.3 PROPOSED SETTINGS

At present, the RAs do not propose changing the payment proportions for 2015. The proposed payment proportions for 2015 are therefore:

FCPPy for 2015 = 0.3

ECPPy for 2015 = 0.3

The VCPP is thus implicitly proposed to be retained as:

VCPPy for 2015 = 0.4

Views are invited on the appropriate values for FCPPy and ECPPy for 2015.

8 VIEWS INVITED

Views are invited regarding any and all aspects of the proposals put forward in this Consultation Paper, and should be addressed (preferably via email) to Kenny Dane at kenny.dane@uregni.gov.uk by **5pm on 28 May 2014**.

The SEM Committee intends to publish all comments received. Those respondents who would like certain sections of their responses to remain confidential should submit the relevant sections in an appendix marked confidential together with an explanation as to why the section should be treated as confidential.

9 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

Table A1.1 – ACPS for Previous Trading Years

10 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