Single Electricity Market

Capacity Requirement and Annual Capacity Payment Sum for Calendar Year 2014

Consultation Paper

14 May 2013

SEM-13-030

1 EXECUTIVE SUMMARY

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 cost was fixed and indexed for three years.

The annualised fixed cost, net of estimated Infra-Marginal Rent and Ancillary Services revenue determined for the 2013 ACPS was €78.18/kW/year. When adjusted for inflation, the BNE cost for the 2014 ACPS is €80.36/kW/year.

The Capacity Requirement for 2014, calculated using a similar methodology to previous years, is 7,049MW.

The product of these price and quantity elements yields an Annual Capacity Payment Sum for 2014 of €566,437,038.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2014	80.36	7,049MW	€566,437,038

This compares to an ACPS of €529,876,722 for the 2013 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 implemented. The SEM is a gross mandatory pool which includes a marginal energy pricing system and an explicit Capacity Payment Mechanism ("**CPM**").

The CPM is a fixed revenue mechanism which collects a pre-determined amount of money, the Annual Capacity Payment Sum ("**ACPS**") from suppliers and pays these funds to available generation capacity in accordance with rules set out in the Trading and Settlement Code ("**TSC**"). 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[2]. 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[3] 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. The paper 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.allislandproject.org/en/capacity-payments-consultation.aspx?page=2&article=0e5940cb-4c5d-4e01-982d-2b3587c33d2d

[3] 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 was used for the calculation of the fixed costs of a BNE peaking plant for all subsequent years. The consultation paper and final decision paper for 2013 were published on the AIP website[4]. 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.

3.1 OUTCOME OF MEDIUM TERM REVIEW

In March 2012, the SEM Committee published the final decision paper on the CPM Medium Term Review (SEM-12-016)[6]. The decisions made are described in full in the decision paper and are summarised below.

3.1.1 FORCED OUTAGE PROBABILITY

Previously, the Forced Outage Probability ("**FOP**") was defined as 4.23%. The revised targeted FOP was set at 5.91%

3.1.2 INFRA MARGINAL RENT

The SEMC decided that Infra Marginal Rent ("**IMR**") should be deducted from the BNE through the following calculation:

IMR DEDUCTED IN €/KW = [PCAP-BID]/100 * OUTAGE TIME * (1-FOP)

[4] Consultation Paper and Final Decision Paper for 2013
[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

This method should reduce the level of volatility and/or potential uncertainty currently in place regarding the IMR deduction. The key variables in the method are semi-fixed such as the Trading and Settlement Code Price Cap (PCAP) and Generation Security Standard (GSS / Outage Time). Therefore the deduction should be capable of being forecast by investors with reasonable accuracy.

3.1.3 THE BNE WILL REMAIN CONSTANT FOR THREE YEARS

The RAs consider that a ‘Component Period Horizon’ of three years can bring some stability and certainty to the volatility in the annual capacity payment sum. There is merit in a commitment period greater than one year in that capacity providers will have greater certainty as to the remuneration for their capacity provision. Elements such as the Technology Options/EPC Investment costs will remain constant but indexed over the following two years.

For indexing, the €/kW/year value will be determined by taking its value in the preceding years and applying the annual inflation rate in the jurisdiction that the BNE is located. For example, if the BNE is in Northern Ireland and a UK WACC is used, then the UK inflation rate will be used to index the €/kW/year value.

Other elements such as the Capacity Requirement and the TSC parameters will continue to be calculated on an annual basis in conjunction with the TSOs.

3.1.4 ANCILLARY SERVICES DEDUCTIONS

The expected revenue the BNE is expected to earn from Ancillary Services will continue to be deducted from the annualised cost of the BNE.

In 2012 the TSOs in cooperation with the Regulatory Authorities began a systems services Review (DS3[7]) multi-stage consultation process, to incorporate the views of industry on the arrangements for system services. The TSOs are currently investigating the specific definitions of system services and the requirement quantities over the medium to long term. These proposals / services identified may impact the Ancillary Services revenues earned by the BNE over the three year period. The RAs reserve the option to review the Ancillary Services reduction in future years of this period, if they believe it is appropriate to do so.

[7] http://www.eirgrid.com/operations/ds3/

4 BEST NEW ENTRANT PEAKING PLANT PRICE FOR 2014

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 costs and the final annualised cost of the BNE Peaker for 2013. 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 2013 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 2.79% between February 2012 and February 2013[9]. The annualised BNE cost per kW to be used in the 2014 Annual Capacity Payment Sum is therefore €80.36/kW/year.

	Decision 2013	Proposed 2014
Annualised Cost per kW per year	88.14	90.60
Ancillary Services	4.37	4.49
Infra-Marginal Rent	5.59	5.75
BNE Cost per kW per year	**78.18**	**80.36**

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

[9] http://www.ons.gov.uk/ons/publications/re-reference-tables.html?edition=tcm%3A77-276818

5 CAPACITY REQUIREMENT FOR 2014

5.1 INTRODUCTION

The methodology used for calculating the Capacity Requirement for 2014 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 2014 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 2014

The following sections describe further each of these parameter settings used in the calculation of the 2014 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 2014 calculation.

5.3.2 DEMAND FORECAST

For the purposes of calculating the Capacity Requirement, the demand forecast was taken from the medium table of the Eirgrid / SONI forecast in Appendix 1 of the 2013-2022 All-Island Generation Capacity Statement[10].

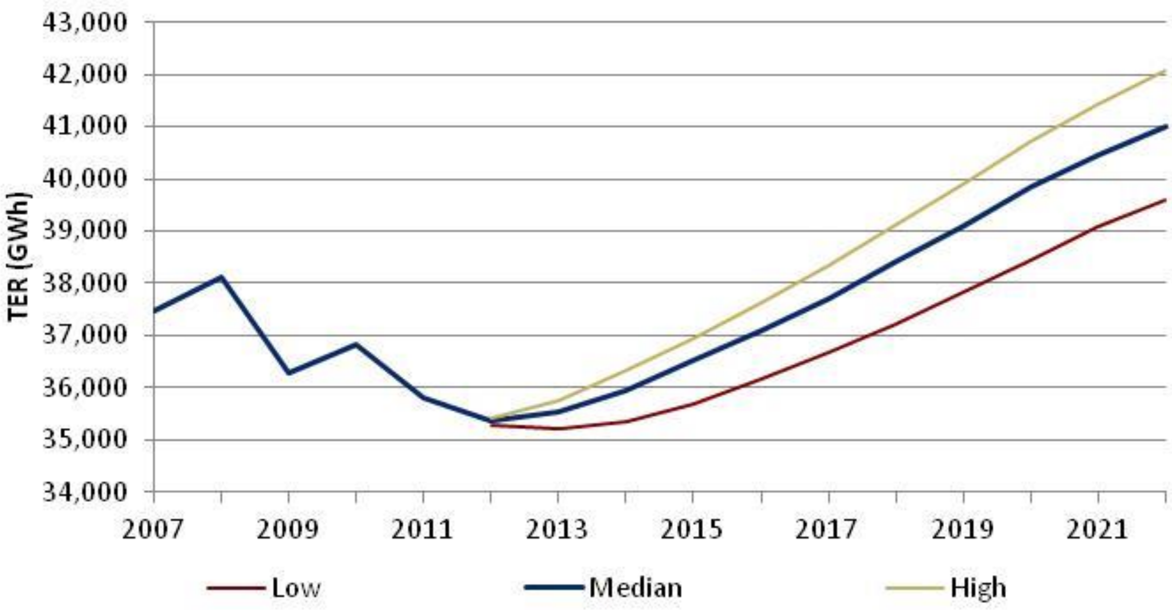

Figure 5.1 All-Island Demand Forecast [11]

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

For the 2014 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:

	2014 Forecasted Total Energy Requirement
Republic of Ireland	26,859
Northern Ireland	9,103
All-Island	35,962

Table 5.1 – *Demand Forecast*

[10] http://www.soni.ltd.uk/upload/All-island_GCS_2013-2022.pdf

[11] Chart based on Figure 2-7, Page 22 , All-island Generation Capacity Statement 2013-2022

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.

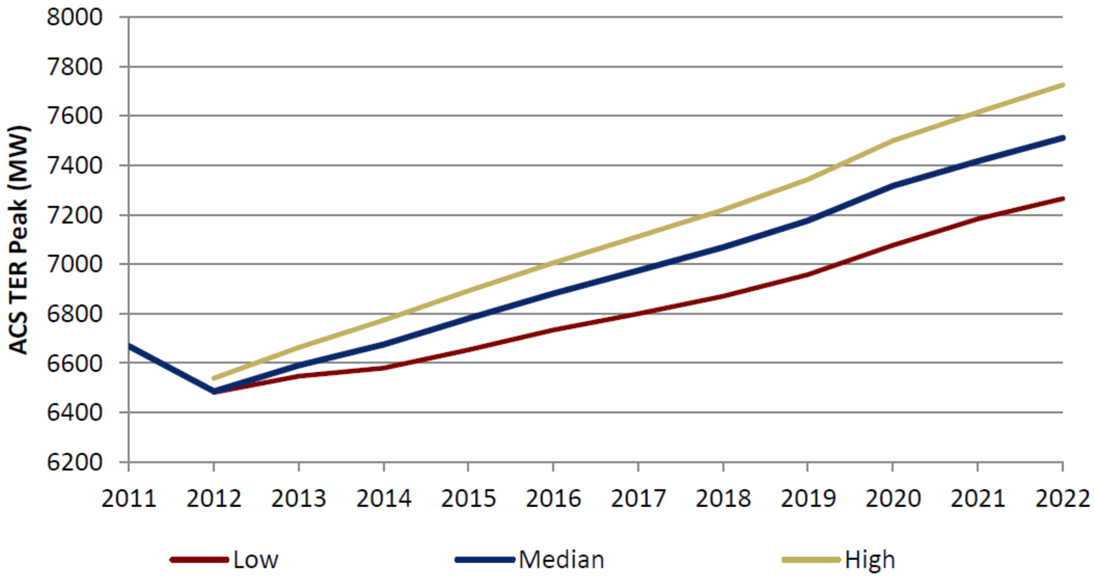

Figure 5.2 All-Island Peak Demand Forecast

Forecasted peak demand has increased by 269MW from the forecast used for the 2013 Capacity Requirement (6,397MW) to the forecast used for the 2014 Capacity Requirement (6,666MW)[12].

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 2013-2022. This was cross-checked against the 2012-13 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 2014 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

[12] Please note that the 2013 Capacity Requirement was recalculated after the initial consultation and was based upon outturn demand for 2011 and trends for 2012 up to the end of April.

calendar year. This process has continued to be applied in formulating the scheduled outage inputs for each unit in the 2014 Capacity Requirement process.

5.3.5 FORCED OUTAGE PROBABILITIES

The Decision Paper AIP/SEM/07/13 sets 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 Section 4 above and 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 2014 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 2014 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 2014 that arises from the conventional market capacity, employed to meet the 2014 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 2014

The inputs used in the 2014 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 2014	A combined load forecast for 2014, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. Two traces were agreed: 1) Total Load Forecast for 2014 2) Total (In Market) Conventional Load Forecast See Appendix 3 – Load Forecast for 2014
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 2014, 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 **9,961MW** See Appendix 4 – Generation Capacity for 2014
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 2014 used was **2,759MW**. This results in a Capacity Credit of **0.149**. The Time Weighted Market Wind Capacity in 2014 was **2,160MW**. Therefore the Wind Capacity Credit is derived as **322MW** (2,160 x 0.149) See Appendix 5 – Wind Capacity in 2014
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.

	See Appendix 6 – Average SOD for 2014
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 2014 is **7,049MW.** This is an increase of 271MW from the Capacity Requirement for 2013 of 6,778MW.

The Proposed Capacity Requirement for 2014 is 7,049MW

6 INDICATIVE ANNUAL CAPACITY PAYMENT SUM FOR 2014

Based on the annualised fixed cost of the BNE Peaker and the Capacity Requirement for 2014 as detailed above, the Annual Capacity Payments Sum (ACPS) for 2014 is proposed to be €566.43m. The proposed figures are detailed in table 6.1 below.

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2014	80.36	7,049MW	€566,437,038

Table 6.1 – ACPS for the Trading Year 2014

The Proposed Annual Capacity Payments Sum (ACPS) for 2014 is €566.43m

7 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 11 June 2013**.

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

8 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 the Trading Years 2007, 2008, 2009, 2010, 2011, 2012 and 2013 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

Table A1.1 – ACPS for Previous Trading Years

9 APPENDIX 2 – LOW/MEDIUM/HIGH DEMAND FORECAST

Med	Total Electricity Requirement (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
2012	26,320	-1.3%	9,037	-1.2%	35,357	-1.3%	4,779	1,776	6,485	4,680	1,731	6,341
2013	26,503	0.7%	9,028	-0.1%	35,532	0.5%	4,882	1,779	6,591	4,768	1,733	6,431
2014	26,859	1.3%	9,103	0.8%	35,962	1.2%	4,952	1,794	6,676	4,825	1,747	6,501
2015	27,252	1.5%	9,259	1.7%	36,511	1.5%	5,030	1,823	6,781	4,888	1,773	6,590
2016	27,670	1.5%	9,418	1.7%	37,088	1.6%	5,102	1,852	6,881	4,946	1,800	6,674
2017	28,152	1.7%	9,575	1.7%	37,727	1.7%	5,167	1,881	6,974	4,996	1,828	6,751
2018	28,677	1.9%	9,731	1.6%	38,408	1.8%	5,232	1,910	7,068	5,048	1,856	6,829
2019	29,230	1.9%	9,886	1.6%	39,117	1.8%	5,313	1,941	7,177	5,114	1,885	6,923
2020	29,808	2.0%	10,043	1.6%	39,852	1.9%	5,422	1,971	7,317	5,210	1,915	7,049
2021	30,245	1.5%	10,201	1.6%	40,446	1.5%	5,494	2,002	7,417	5,281	1,946	7,148
2022	30,651	1.3%	10,361	1.6%	41,011	1.4%	5,559	2,034	7,511	5,346	1,977	7,241

TableA2-1: Median Demand Forecast

Low	Total Electricity Requirement (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
2012	26,320	-1.3%	8,972	-1.9%	35,292	-1.4%	4,779	1,772	6,482	4,680	1,728	6,337
2013	26,320	0.0%	8,891	-0.9%	35,212	-0.2%	4,848	1,769	6,546	4,734	1,723	6,387
2014	26,451	0.5%	8,886	-0.1%	35,337	0.4%	4,876	1,774	6,579	4,748	1,727	6,404
2015	26,753	1.1%	8,953	0.7%	35,705	1.0%	4,936	1,790	6,653	4,794	1,740	6,462
2016	27,090	1.3%	9,089	1.5%	36,180	1.3%	4,992	1,814	6,734	4,836	1,763	6,526
2017	27,452	1.3%	9,224	1.5%	36,675	1.4%	5,034	1,839	6,800	4,864	1,786	6,577
2018	27,875	1.5%	9,356	1.4%	37,231	1.5%	5,081	1,865	6,871	4,897	1,810	6,632
2019	28,339	1.7%	9,487	1.4%	37,826	1.6%	5,144	1,890	6,958	4,946	1,835	6,705
2020	28,830	1.7%	9,619	1.4%	38,449	1.6%	5,237	1,916	7,077	5,025	1,860	6,808
2021	29,342	1.8%	9,751	1.4%	39,093	1.7%	5,320	1,943	7,184	5,108	1,886	6,915
2022	29,713	1.3%	9,885	1.4%	39,599	1.3%	5,378	1,969	7,266	5,166	1,912	6,996

Table A2-2: Low Demand Forecast

High	Total Electricity Requirement (GWh)						TER Peak (MW)			Transmission Peak (MW)		
Year	Ireland		Northern Ireland		All-Island		Ireland	Northern Ireland	All-Island	Ireland	Northern Ireland	All-Island
2012	26,320	-1.3%	9,113	-0.4%	35,433	-1.0%	4,829	1,779	6,539	4,729	1,735	6,394
2013	26,556	0.9%	9,191	0.9%	35,746	0.9%	4,941	1,792	6,663	4,827	1,747	6,504
2014	26,966	1.5%	9,364	1.9%	36,329	1.6%	5,020	1,824	6,773	4,892	1,777	6,598
2015	27,414	1.7%	9,542	1.9%	36,956	1.7%	5,107	1,856	6,892	4,965	1,807	6,701
2016	27,889	1.7%	9,724	1.9%	37,613	1.8%	5,189	1,889	7,006	5,033	1,838	6,798
2017	28,431	1.9%	9,906	1.9%	38,336	1.9%	5,262	1,923	7,112	5,092	1,870	6,889
2018	29,017	2.1%	10,086	1.8%	39,103	2.0%	5,338	1,957	7,220	5,153	1,903	6,982
2019	29,636	2.1%	10,266	1.8%	39,902	2.0%	5,428	1,992	7,344	5,229	1,937	7,090
2020	30,281	2.2%	10,449	1.8%	40,731	2.1%	5,549	2,028	7,499	5,336	1,971	7,231
2021	30,786	1.7%	10,633	1.8%	41,419	1.7%	5,630	2,064	7,615	5,418	2,007	7,346
2022	31,260	1.5%	10,821	1.8%	42,080	1.6%	5,707	2,100	7,726	5,495	2,043	7,456

Table A2-3 High Demand Forecast