Single Electricity Market

Fixed Cost of a Best New Entrant Peaking Plant,

Capacity Requirement and

Annual Capacity Payment Sum

For Trading Year 2018

Consultation Paper

10 July 2017

SEM-17-047

1 EXECUTIVE SUMMARY

The Capacity Payment Mechanism is a fixed revenue mechanism which collects a pre-determined amount of money through charges levied on participants who purchase energy from the pool. . These funds are paid to available generation capacity in accordance with rules set out in the SEM Trading and Settlement Code. The 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 notional best new entrant peaking plant.

The notional 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 2016[1]. In accordance with the decision described in the 2016 Final Decision paper, its costs have been fixed and indexed for 2018.

Following the result of the UK's referendum on its membership of the EU, the value of the pound against the euro fell markedly. The exchange rate of the pound against the euro has continued to fluctuate. A weakened pound has several implications for various aspects of the UK economy, notably imports and exports and the price of goods and services.

This is an unprecedented and material change in the value of Sterling against the Euro that *materially effects the indexation outcome for the ACPS*. As such, the SEM Committee herein propose two values of the ACPS for the Trading Year 2018. In what follows both the existing methodology and another that seeks to dilute the material impact of Brexit on the BNE figure.

This paper sets out the rationale for the SEM Committee's proposal to index in two ways.

In the first approach "Calculation 1", the BNE 2018 figures are calculated using the same indexation methodology that was used for the 2017 BNE calculation, i.e. the previous year's value (2017 BNE value) adjusted by the current sterling RPI value to derive the BNE for 2018.

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

In light of significant exchange rate fluctuations the second alternative, “Calculation 2” proposes another approach to indexation. In this approach the original sterling 2015 costs are indexed to account for RPI from 2015 to 2017, these inflated costs are then converted to EUROS at the current forward FX rate for Sterling/EURO to derive the BNE for 2018.

In section 3, the BNE figures for both calculations are determined, and set out, Section 5 outlines the Annual Capacity Payment Sums based on both BNE figures.

In Calculation 1, the RAs have started with the 2016 BNE figure. Determined for the Trading Year 2017, the fixed costs of running a peaking plant in the SEM was €85.08 /kW/year. When this is adjusted for inflation[2] the 2018 annualised cost becomes €88.06/kW/year. This figure is referenced as Calculation 1 (“**C1**”). Once infra-marginal rent and ancillary services revenues are deducted the annualised cost becomes **€74.04/kW/year**.

In the second of the two BNE calculations, the RA’s have calculated a fixed cost of running, based on an indexation and foreign exchange on the primary cost drivers of the Total Investment Costs, as set out in the 2016 Consultation paper (SEM-15-032). Once these investment costs are converted to Sterling (at 2016 rates) and indexed using RPI then converted back to Euros (at a forward looking 2018 rate) the annualised fixed costs of running are €77.53/kW/yr. This figure is referenced as Calculation 2 (“**C2**”). Once infra-marginal rent and ancillary services revenues are deducted the annualised cost becomes **€63.51/kW/year**.

The Capacity Requirement for 2018, calculated using a similar methodology to previous years, is 7368 MW.

These price and quantity elements yields, two values for the ACPS’ for 2018, both of which are shown below.

Table 1.1 Indicative Annual Capacity Payment Sum 2018

Year	BNE Peaker Cost (€/kW/yr)	Capacity Requirement (MW)	ACPS (€)
2018 (C1)	74.04	7368	545,526,720
2018 (C2)	63.51	7368	467,941,680

[2] The Retail Price index (RPI) figure of 3.5% used here is the April 2017 figure (published 16 May 2017), the time series can be found at https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/czbh

The RAs have therefore published the Capacity Period Payment Sum ("**CPPS**") indicating the monthly sums to be paid. Following on from the 2017 CPPS below, the two updated CPPS' based on two ACPS' are shown below in Table 1.2.

Table 1.2: Capacity Period Payment Sums 2017

Month	Capacity Period Payment Sum 2017
January	€52,528,632
February	€50,835,766
March	€46,925,877
April	€39,121,029
May	€36,236,557
June	€34,256,102
July	€32,505,450
August	€35,729,847
September	€35,696,498
October	€45,397,053
November	€52,555,995
December	€55,080,767
Total	**€519,227,150**

The Capacity Period Payment Sums from the 2017 Final Decision Paper are shown in Table 1.2. It was noted[3] in the decision paper that the Capacity Payment Period Sum 'splits' will be paid up to and including the September 2017 sum. As the I-SEM Go-Live date is now 23 May 2018, the SEM Committee propose to use the values (grey fill above) as the CPPS calculated for the remaining months as published, to constitute the monthly CPPS values in those months. Furthermore, the SEM Committee propose to extend the CPM to the end of the SEM using the monthly amounts published in this paper.

Table 1.3 below shows the 2018 Capacity Payment Period Sum based on a BNE figure calculated using the existing methodology.

Table 1.3: Capacity Period Payment Sums 2018 – Consultation based on Calculation 1

Month	Capacity Period Payment Sum 2018
January	€53,881,528
February	€54,508,065
March	€50,340,028
April	€41,502,867

[3] Executive Summary, Final Decision Annual Capacity Payment Sum 2017
https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-044%20Final%20Decision%20ACPS%202017.pdf

May	€38,998,618
Total until end of SEM	**€239,231,106**[4]
June	€35,917,495
July	€37,556,299
August	€38,773,376
September	€43,057,909
October	€50,009,495
November	€49,119,528
December	€51,861,512
2018 Grand Total (C1)	**€545,526,720**

Table 1.4 below shows the 2018 Capacity Payment Period Sum based on a BNE figure calculated using the alternative indexing approach.

Table 1.4: Capacity Period Payment Sums 2018 – Consultation based on Calculation 2

Month	Capacity Payment Period Sum 2018
January	€46,218,475
February	€46,755,905
March	€43,180,648
April	€35,600,312
May	€33,452,218
Total until end of SEM	**€205,207,558**
June	€30,809,294
July	€32,215,026
August	€33,259,010
September	€36,934,195
October	€42,897,124
November	€42,133,728
December	€44,485,745
2018 Grand Total (C2)	**€467,941,680**

As in the 2017 decision, it is the SEM Committee's intention to publish the full 2018 Capacity Payment Period Sum, with the added caveat that the current Capacity Payment Mechanism will cease in May 2018.

Market Participants will note that there are many parameters in this consultation paper that do not match necessarily to similar parameters that underpin the design of the Capacity

[4] This is the sum of the first five months. In reality the amount paid in May 2018 will depend on the relative Loss of Load probabilities during the 22 days of SEM compared to the 9 days of I-SEM.

Remuneration Mechanism. In particular the Capacity Requirement value presented within this paper is not equal to the value of the requirement for the I-SEM CRM. The SEM Committee feel it pertinent to reinforce comments within a recent CRM paper[5] that discuss these differences.

The SEM Committee note that the observed differences are due to the fact that the methodology employed in the CRM paper determines a de-rated capacity requirement rather than the *installed* requirement, with notional outage rates, determined for the Annual Capacity Payment Sum.

[5] §9.2, *I-SEM Capacity Remuneration Mechanism: Proposed Methodology for the Calculation of the Capacity Requirement and De-rating Factors* https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-051a%20Appendix%201%20TSOs%20Capacity%20Requirement%20and%20De-rating%20Factors%20Methodology.pdf

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2 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**")[6]. 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

[6] 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 for Trading Year 2016. The consultation paper proposed once again fixing the BNE element for the Trading Year 2017 to provide stability to generators in light of the SEM ending and as the new I-SEM goes live in 2017, by indexing the 2016 BNE value. The decision paper was then published on 4 September 2016 (SEM-16-059). It was decided within the decision paper that the BNE element will be inflated through the Retail Price Index ("**RPI**") for 2017. The SEM Committee approved inflating using RPI rather than the previously used Consumer Price Index ("**CPI**").

It was noted[7] in the decision paper that the Capacity Payment Period Sum (CPPS) 'splits' will be paid up to and including the September 2017 pot. As the I-SEM Go-Live date is now 23 May

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[7] Executive Summary, Final Decision Annual Capacity Payment Sum 2017
https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-044%20Final%20Decision%20ACPS%202017.pdf

2018, the SEM Committee propose to use the values as the CPPS calculated for the remaining months of 2017 as published to constitute the monthly CPPS values in the months October, November and December 2017. Furthermore, the Committee propose to extend the CPM to the end of the SEM (May 2018) using the monthly amounts published in this paper.

3 BEST NEW ENTRANT PEAKING PLANT FOR 2018

In the decision paper on the Fixed Cost of a BNE peaking plant, Capacity Requirement and Annual Capacity Payment Sum for the Calendar Year 2016[8], the BNE for 2016 and 2017 was determined as an Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland.

As the I-SEM Go-Live date of 23 May 2018 approaches, the RAs intend to maintain the selection of the Alstom GT13E2 firing on distillate fuel, sited in Northern Ireland as the BNE used to calculate the ACPS for the Trading Year 2018, similar to the approach used for the 2017 ACPS.

As with the approach used to calculate the 2017 ACPS, the RAs propose to index the 2016 BNE value to calculate the BNE value for 2018. This consultation paper proposes two alternative approaches to this indexation, and these are discussed in more detail below.

The table below provides a summary of the final annualised costs of the BNE Peaking Plant for 2016 and 2017 with the proposed 2018 figures.

There are two values for the fixed costs of a BNE in 2018 in the table below.

This table includes the values based on a deduction of any revenues obtained from Infra Marginal Rent and Ancillary Services (under new DS3 arrangements).

Table 3.1: Indicative 2018 Annual Capacity Payment Sum

	Decision 2016	Decision 2017	Proposed 2018 (C1)	Proposed 2018 (C2)
Annualised Cost per kW per year	83.74	85.08	88.06	77.53
Ancillary Services	4.64	N/A	N/A	N/A
DS3 System Services	N/A	7.34	7.76	7.76
Infra-Marginal Rent	6.28	6.29	6.26	6.26
BNE Cost per kW per year	**72.82**	**71.45**	**74.04**	**63.51**

The section below now discusses the indexation approaches used to calculate these two alternative BNE values in detail.

3.1 INDEXATION OF BNE ANNUALISED COST

[8] http://www.semcommittee.eu/en/cp_decision_documents.aspx?article=879633f4-5b08-42e3-a889-4f86cf0b2667

In the 2015 decision paper, in addition to setting the 2016 value of the BNE, it was decided that the BNE element of the ACPS should be fixed for the final year of the SEM (2017). In 2013, the BNE figure was fixed for three years and inflated in 2014 and 2015 by CPI. During those years (2007-13) where the BNE figure was determined from the ground up, the calculation of the Weighted Average Cost of Capital ("**WACC**") required as an input an estimate of the cost of debt figure. Within this cost of debt determination, the deflation of nominal to real yields on UK Government bonds was determined through deflation by RPI. The indexation of the BNE figure (when fixing for three years from 2013) used CPI.

Following the decision to set the BNE for the 2016 trading year, participants noted that since the conversion of nominal to real yields on UK bonds was through RPI, then the BNE figure should be also be inflated using the same index. The SEM Committee agreed and approved this change for the calculation of the BNE for the 2017 trading year.

As the BNE is located in Northern Ireland, the RPI as measured in the UK was used to index the BNE annualised cost for 2017. The SEM Committee propose to retain RPI as an appropriate inflationary multiplier for the BNE annualised cost for 2018.

When determining this calculation the most recent inflation data available for RPI in the UK showed that average prices in the UK increased by 3.1% between April 2016 and March 2017[9]. In Ireland the most recent inflation data available is the CPI, this data shows a minimal increase of 0.70% between April 2016 and April 2017[10].

This will be re-calculated prior to decision to account for inflation between June 2016 and June 2017[11].

Following the result of the UK's referendum on its membership of the EU, the value of the pound against the euro fell markedly. The exchange rate of the pound against the euro has continued to fluctuate. As of April 2015 the Sterling/Euro exchange rate was 1.3863 the current forward rate for 2018 is 1.1830 this amounts to a decrease in the value of the sterling against euro of 14.7%. A weakened pound has several implications for various aspects of the UK economy, notably imports and exports and the price of goods and services.

[9]For the latest RPI figures used in this calculation, see the relevant pages from the Office of National Statistics http://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/czbh

[10]For the latest CPI figures used in this calculation: http://www.inflation.eu/inflation-rates/ireland/historic-inflation/cpi-inflation-ireland-2017.aspx

[11] The release calendar for UK Indices can be found here http://www.ons.gov.uk/releasecalendar

[12].

In 2015, the SEM Committee approved a decision to calculate a value for the Best New Entrant starting from first principles[13], in order to simulate the costs for procuring a distillate-fired plant and installing and commissioning in Northern Ireland. The values for these fixed costs were initially calculated in Sterling, and were then converted to euros to establish the BNE on a per €/kW/yr basis.

The same decision paper set out the method by which, moving forward until the end of the SEM, the indexation of the BNE will be calculated. The SEM Committee decided at the time to fix the BNE value in 2016, and index the value for 2017 using RPI for UK, as the BNE was assumed to be located in Northern Ireland. The SEM Committee noted at the time that since the investors and participants are operating in two currencies, there are multiple ways to approach the indexation methodology.

In order to offer Market Participants some regulatory certainty and follow best practise, the SEM Committee are proposing to continue to use the indexing approach of the 2016 BNE plant type.

In the context of setting the 2018 BNE, the SEM Committee has examined the appropriateness of the previously adopted indexation approach in the context of the disconnect in inflation rates between Ireland and Northern Ireland, and the significant change in the Sterling/Euro exchange rates in light of recent economic and political developments.

In what follows, the SEM Committee puts forward two approaches to indexation for the BNE. One that is generated via the same methodology as used for the 2017 ACPS, and another that seeks to take into account the recent movements in inflation and exchange rates between the two jurisdictions.

3.2 BEST NEW ENTRANT 2018 (CALCULATION 1)

Using the methodology that was adopted for the 2017 BNE calculation, the value of the BNE was fixed in 2015 (for the 2016 BNE Value) in Euros at the prevailing Euro/Sterling exchange

[12]House of Lords, 3 November 2016, HL2646. http://www.parliament.uk/written-questions-answers-statements/written-question/lords/2016-10-25/HL2646

[13] See *Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement and Annual Capacity Payment Sum for the Trading Year 2016* here SEM-15-032

rate. That 2016 value was inflated by the 2016 Sterling RPI to give the 2017 BNE value. If the same approach was to be adopted in 2018, the 2017 BNE value would be adjusted by the current sterling RPI value. The SEM Committee identified the current value of UK RPI to be 3.1% for March 2017.

Using the most up to date UK RPI the annualised fixed costs of running a peaking plant in the SEM is €88.06/kW/yr. Once this is adjusted for deductions based on Infra-Marginal Rent and Ancillary Services this figure becomes **€74.04/kW/yr.**

As a result of the Midterm Review, the bottom-up approach to calculating the BNE costs was changed to occurring only once every 3 years, rather than every year, and that the value would be indexed for inflation during the interim period. The underlying assumption in this process is that the application of inflation would give a similar answer to a bottom-up assessment, within a tolerable margin of error, and thus that the time and effort saved within the RAs outweighs the lost accuracy of the calculation, along with the benefit of stability for paying the ACPS and receiving payments based on the ACPS. The impact of this is that the costs of the BNE, chosen in the bottom-up assessment process, get 'locked in' for the subsequent years, inflated by inflation only in the subsequent years. As noted above, this process works well as a 'short cut' in the event that currency fluctuations and inflation are relatively stable between the sterling area and euro areas.

In putting forward this alternative, the SEM Committee acknowledges that over the past number of years the SEM Committee has applied the relevant inflation index (currently RPI in the UK, as the BNE is assumed to be located in Northern Ireland) to the euro value of the BNE, that was based on the prevailing exchange rates in the year that the calculation was completed, i.e., 2015.

Having considered this further, the SEM Committee acknowledges that this methodology creates a problem in that the inflation rate in the UK (or any other country) is impacted by foreign exchange rates. In other words, as it becomes more expensive to buy foreign goods in light of a currency's depreciation, inflation goes up. In this way, application of inflation rates in one jurisdiction to the currency in another, 'imports' some of the currency fluctuation. This was acknowledged by a number of respondents over the course of the CPM Midterm Review and also in response to the 2015 consultation.

This mis-match between inflation rates and exchange rates does not lead to any significant issues when inflation and exchange rates are relatively stable. For this reason, the SEM Committee is including in this consultation paper an alternative approach to indexation, discussed below.

3.3 BEST NEW ENTRANT 2018 (CALCULATION 2)

In examining the trends in inflation and exchange rates, the SEM Committee is concerned that the approach to indexing previously used by the SEM Committee to calculate the 2017 BNE may no longer be considered appropriate Given the change in the sterling/euro exchange rate since the 2016, BNE the SEM Committee is proposing an alternative approach to indexing whereby the original costs used to calculate the BNE are indexed based on their original currency values, e.g., Sterling, and then converted to Euros at the prevailing forward exchange rate, to estimate the BNE applicable for 2018.

In setting the 2016 BNE, the SEM Committee completed a bottom up calculation of the BNE, using a range of components, as outlined in SEM-15-032, and shown below in Table 3.2. For the NI based plant, these investment costs were initially estimated in Sterling and then converted to Euro at the Sterling/Euro exchange rate applicable at the time. Under this indexing approach, the 2015 Sterling values of the investment costs would be indexed at RPI from 2015 to 2017/18, and then converted to Euro at the current forward Sterling/Euro exchange rate, to estimate the 2018 BNE value.

The Total investment Costs published in SEM-15-032 are revisited and inflated using RPI on a component by component basis, after converting the values to Sterling. Below is a table outlining these investment costs from the ACPS 2016 Calculation.

Table 3.2 Capital Investment Costs SEM Committee Decision[14]

Capital costs	Units	Alstom GT13E2 NI Distillate (€m)
EPC contract	€m	94.500
Site procurement cost	€m	0.959
Electrical Connection costs	€m	16.592
Water connection	€m	0.512
Owners contingency	€m	4.725
Financing	€m	1.890
IDC	€m	0.624
Construction insurance	€m	0.851
Initial Fuel working capital	€m	3.527
Other non EPC costs	€m	8.505
Accession Fee	€m	0.001
Participation Fee	€m	0.003
Initial Working Capital (Operations)	€m	2.073

[14] See SEM Committee Decision Paper, 4 September 2015 https://www.semcommittee.com/publication/sem-15-059-acps-final-decision-paper

In developing this indexation methodology, it was necessary to identify on what basis the original costs were estimated, to assess whether or not the original 2015 costs should be re-converted back to Sterling and inflated at RPI, prior to conversion to Euro.

Under this method, all costs bar the EPC costs (quoted in Euros) are converted to Sterling, then inflated through RPI and finally converted back to Euros using a forward looking 2018 exchange rate. The rationale for the varying treatment of different cost components is provided below.

Engineering, Procurement, and Construction (EPC)

EPC is a particular form of contracting arrangement used in some industries where the EPC Contractor is made responsible for all the activities from design, procurement, construction, to commissioning and handover of the project to the End-User or Owner.
The Best New Entrant Peaker initially selected for 2016 is the Alstom GT13E2. This is manufactured in the EU (France) and therefore the assumption made is that the cost would be likely to be accrued in Euro and the change in the exchange rate is not an issue. This figure is inflated to a 2017 value.

Site Procurement costs

This is the cost incurred while considering the optimum location for the BNE peaking plant. This could include locational transmission charging differences, financing costs and site availability.

On the basis that the BNE would continue to be in NI, the assumption made is these costs would be predominately local and therefore incurred in Sterling. On this basis, the 2015 values in Euro are adjusted by RPI and the current exchange rate to bring them to a 2017 Euro value.

Electrical Connection costs

The cost of the transmission connection is a significant cost in the calculation. At €16.5 million it is the second largest investment cost in the analysis. As the BNE is located in NI this will be paid for in Sterling, and therefore the 2015 Euro values are adjusted by RPI and the current exchange rate to bring them to a 2017 Euro value.

Gas and make up water connection costs

This is the cost of securing a water supply and connection to the gas network (where applicable). As the unit type is assumed to be distillate, there is no gas connection cost. As the BNE is located in NI this will be paid for in sterling and will be adjusted to bring it to a 2017 euro value.

Owner's contingency

This is an amount added to the estimate EPC to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result in additional costs.
From assessing previous commentary in relation to this cost, there is no clear linkage to either currency. On this basis, the 2015 euro value is inflated to a 2017 value only.

Interest During Construction (IDC)

This refers to the financing charges incurred during the creation of the plane. In this instance the financing has been estimated as a proportion of EPC costs.
It is not possible to determine the jurisdiction in which financial support originates. As with other areas, as this is an unknown variable the assumption has been taken that this is a euro cost.

Construction Insurance

Insurance is normally purchased within the jurisdiction which the construction is taking place. The assumption made is that insurance will be paid for in sterling and the 2015 value is adjusted to account for the exchange rate and inflation.

Up- front costs for fuel working capital

This is the cost of fuel necessary to comply with various regulatory policies as a BNE cost. Fuel cost are generally paid for in USD, and is therefore subject to FX risk.
For the purposes of this analysis the assumption has been made that euro was used to buy the USD. For simplicity, the 2015 euro value is used and inflated to a 2017 value.

Other non-EPC costs

Other non EPC costs include the costs associated with Environmental Impact Assessment, legal, administration commissioning, operating & maintenance costs and spare parts.
It is likely that the majority of these non EPC costs such as spare parts and maintenance will be incurred in euro, and therefore, the 2015 values is used and inflated to a 2017 value.

The below summarises the assumptions regarding currency costs:

Cost Type	Amount (€m)	EURO/POUND
EPC costs	€94.500	EURO
Site procurement costs	€0.959	STERLING
Electrical Connection cost	€16.592	STERLING
Water connection	€0.512	STERLING
Gas connection	€0.000	STERLING
Owners contingency	€4.725	EURO
Financing costs	€1.890	EURO
IDC	€0.624	EURO
Construction insurance	€0.851	STERLING
Initial Fuel	€3.527	EURO/USD
Non EPC costs	€8.505	EURO
Accession fees	€0.001	EURO
Participation fees	€0.003	EURO

Each row item in the above table will go through a process of multiplication by a 2016 GBP/EUR foreign exchange value, then indexed through March 2016 and 2017 RPI until finally being converted to EUR though a forward looking 2018 EURGBP exchange rate.

Applying this method to the investment costs above, the table below shows the updated ACPS Investment Costs. By way of example, further in this section, a row item from this table will be shown along with all steps in taking Table 3.2, and converting it to the figures seen in Table 3.3.

Table 3.3 Capital Investment Costs; forward looking 2018

Capital costs	Units	Alstom GT13E2 (2018 €m)
EPC contract	€m	94.547[15]
Site procurement cost	€m	0.837
Electrical Connection costs	€m	14.483
Water connection	€m	0.447
Owners contingency	€m	4.124
Financing	€m	1.650
IDC	€m	0.545
Construction insurance	€m	0.742
Initial Fuel working capital	€m	3.079
Other non EPC costs	€m	7.424
Accession Fee	€m	0.001
Participation Fee	€m	0.002
Initial Working Capital (Operations)	€m	1.810

An example of the updated method is now shown in the next section.

3.3.1 EXAMPLE OF CALCULATION USING FORWARD RATES AND INDEXATION

Table 3.3 shows the updated Investment Costs used in the calculation of a Best New Entrant Peaking Plant. These values were calculated through the initial Investment Costs shown in Table 3.2.

All row items in the table have followed the same indexation method bar the EPC Contract price, which (as footnote 15 alludes to) has been inflated using historic 2017/17 (12 month) Ireland CPI figures.

The remaining components are calculated using a similar method, but to dilute the effects on foreign exchange rates from Euro to Sterling, these remaining rows have been converted using a combination of historic EURGBP conversion rates and forward-looking 2018 rates.

[15] The EPC Contract figure has been inflated using Ireland CPI, which, based on 12 month change (May 2016 = 0%, March 2017 = 0.5%) gives a CPI inflator of (1+0.00) x (1+0.05) x €94.5m = €94.547m in 2018.

As an example, the row titled 'Site Procurement Costs' in Table 3.3 have been multiplied by a combination of exchange rates / indexation figures. Hence

1. **€**0.959m x 0.70436 £/€ = **£**0.68m (*2015 July EURGBP rate*)
2. **£**0.68m x (1+0.016) x (1+ 0.031) = **£**0.71m *(RPI Indexation*)
3. **£**0.71m x 1.18303[16] €/£ = **€**0.837m (*Currency exchanged using forward-looking 2018 GBPEUR rate*)

This process of switching back to Euro following indexation is then applied to all investment costs in Table 3.2 to arrive at Table 3.3.

Total Investments costs for the 2018 exercise are shown below, compared to the 2016 values.

Table 3.4 Total Investment Costs 2018[17]

Total Investment Costs (€m)	Value (€m)
2016	€129.161
2018	€124.800

In line with the 2016 calculation, the RAs assume that an efficiently financed peaking plant would broadly seek to match the maturity of its debt profile to the anticipated lifetime of the project. This is set to 20 years. Once this is taken into consideration the annualised fixed costs of running based on the Total Investment Costs for 2018 in Table 6.3 as is €77.53/kW/yr.

The deductions for Infra-Marginal Rent and Ancillary Services remain the same as in sections 3.4 and 3.5 and hence the BNE costs for 2018 become **€63.51/kW/yr.**

[16] Based on historic 2017 values compounded over 12 months.

[17] These values are net of Fuel Working Capital. As set out in SEM-15-032 it is assumed that costs associated to up-front purchasing of fuel, are reclaimed at the end of the plant life by selling the fuel back.

3.4 DEDUCTION FOR INFRAMARGINAL RENT

The deduction for Inframarginal Rent ("**IMR**") will be calculated using the following formula that was set out in the CPM Mid Term Review:

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

For indicative purposes, the deduction for infra-marginal rent has been calculated according to generator commercial offer data on 15 May 2017. The bid figure determined on this day was €168.36/MWhr. This will be re-calculated post-consultation in late June ahead of the final decision. Inputting into the above formula, gives an deduction based on IMR of **€6.26/kW/yr/**

3.5 ANCILLARY SERVICES DEDUCTION

Since SEM Go-Live in November 2007, the BNE fixed costs have been reduced by the earnings received in relation to Ancillary Services ("**AS**"). The current 2016 ACPS was the last time that revenues from HAS would be deducted as the System Services earnings are supplanted by the new DS3 services for 2017.

In 2016, the TSOs provided information on the capabilities per service that the Alstom GT13E2 can provide under DS3, the RAs then formulated the appropriate deduction.

The **€7.76/kW/yr** value was based on the 2017/18 interim tariffs for DS3.

Tariffs may change toward the Final 2018 Decision stage, should that be the case, the figure above will be recalculated to appropriately reflect revenues earned through System Services.

4 CAPACITY REQUIREMENT FOR 2018

4.1 INTRODUCTION

The methodology used for calculating the Capacity Requirement for 2018 is the same as used in previous years' calculations. This section details the individual components and the calculations that have been performed in evaluating this input to the ACPS 2018 figure.

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.

4.2 BACKGROUND TO CALCULATION OF CAPACITY REQUIREMENT PROCESS

The Capacity Requirement 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 consultation took place following an initial paper in March 2006 titled '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.

4.3 PARAMETER SETTINGS FOR CAPACITY REQUIREMENT FOR 2017

The following sections describe further each of these parameter settings used in the calculation of the 2018 Capacity Requirement.

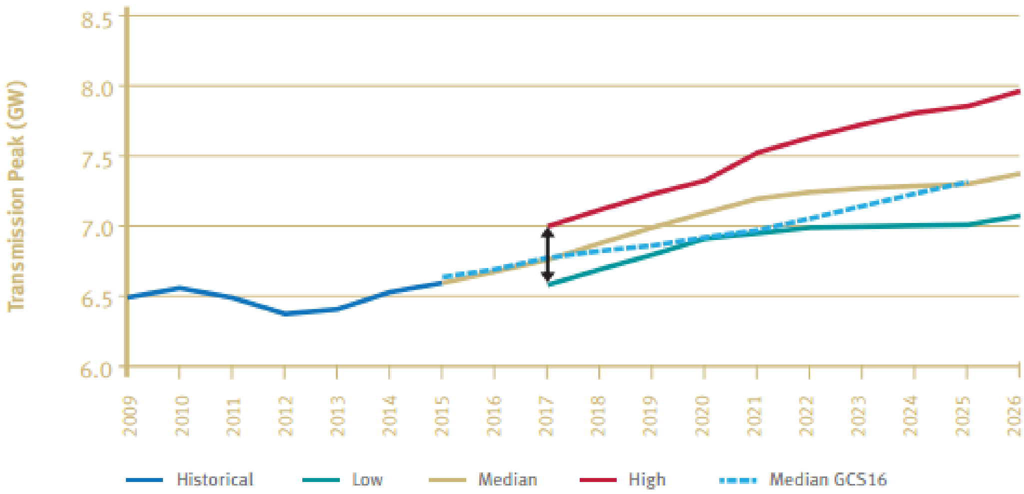
4.3.1 GENERATION SECURITY STANDARD (GSS)

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 2018 calculation.

4.3.2 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 2017-2026 All-Island Generation Capacity Statement[18]. This forecast is stated in terms of the Total Energy Requirement (total energy exported from generating units, plus self-consumption).

Figure 4.1 All-Island Demand Forecast [19]



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

For the 2018 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 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:

[18] The 2017-26 GCS can be found at the following http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf

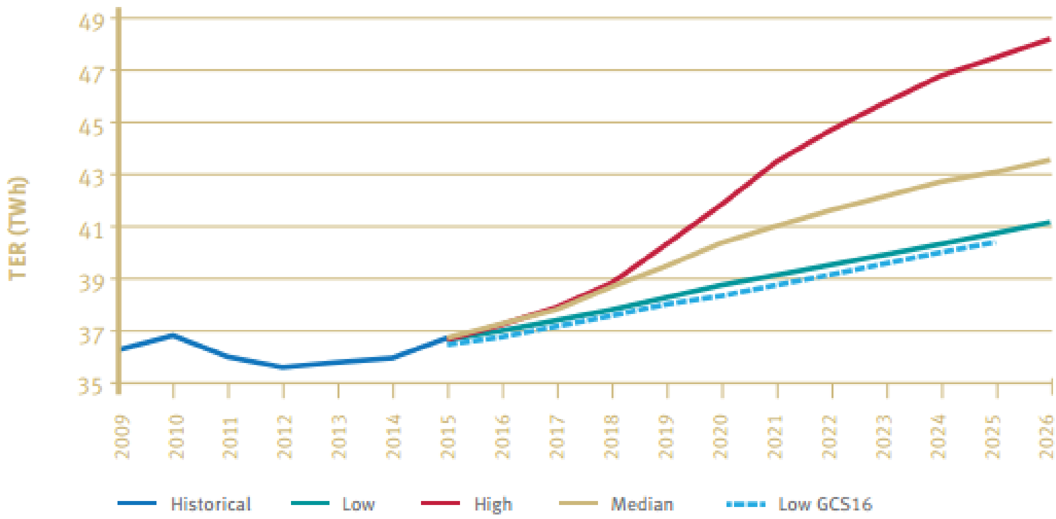
[19] Chart taken from Figure 2-10 , page 31 of the All-island Generation Capacity Statement 2017-26.

Table 4.1: Forecasted Total Energy Requirement (TER)

	2018 Forecasted Total Energy Requirement
Republic of Ireland	28,600
Northern Ireland	9,090
All-Island	37,690

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 4.2 All-Island Peak Demand Forecast



The 2015 Load shape was used in the determination of the figure above. A least worst regrets analysis is implemented alongside an Average Cold Spell (ACS) analysis to determine peak demand scenarios[20].

4.3.3 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

[20] Figure 2-9 taken from GCS 2017-26, page 31 http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf

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 2018 Capacity Requirement process.

4.3.4 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%. It is this figure that is used in the 2018 Calculation.

4.3.5 TREATMENT OF WIND

The Decision Paper AIP/SEM/07/13 explained the RAs' decision to treat wind as a netting trace against the load trace. This process has been repeated in the 2018 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.

4.3.6 ADCAL CALCULATION PROCESS

Having collected together the various input data points, the TSOs ran the iterative ADCAL software process to calculate the 2018 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 2018 that arises from the conventional market capacity, employed to meet the 2018 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 the value 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.

4.4 PROPOSED CAPACITY REQUIREMENT FOR 2018

The inputs used in the 2018 consultation calculations are summarised below. The associated data sets are attached as appendices to this paper.

Table 4.3: Methodology in Determining the Capacity Requirement

Input	Description
Load Forecasts for ROI and NI for 2017	A combined load forecast for 2018, on a half hourly basis for both jurisdictions, was created and agreed with the TSOs. Two traces were agreed: 1) Total Load Forecast for 2018 2) Total (In Market) Conventional Load Forecast 2018
Generation Capacity	A list of all generation to be in place in 2018 was determined, including the Sent Out Capacity for each unit. For any units to be commissioned or decommissioned during 2018, the Capacity available was adjusted accordingly to reflect the actual period they are available (time weighted average).
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
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.
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.

As a result of the analysis carried out in conjunction with the TSOs, the RAs have determined that the Capacity Requirement for 2018 is **7,368 MW.** This is an increase of 101MW from the Capacity Requirement for 2017 of 7,267MW.

The Proposed Capacity Requirement for 2018 is 7368 MW

5 INDICATIVE ANNUAL CAPACITY PAYMENT SUM(S) FOR 2018

Based on the annualised fixed cost of the BNE Peaking Plant in Calculation 1 and the Capacity Requirement the ACPS for 2018 (C1) is determined to be.

Table 5.1: Annual Capacity Payment Sum 2018 (C1 Calculation)

Year	BNE (€/kW/yr)	Capacity Req (MW)	ACPS (C1,€)
2018	74.04	7368	545,526,720

Based on the annualised fixed cost of the BNE Peaking Plant in Calculation 2 and the Capacity Requirement the ACPS for 2018 (C2) is determined to be

Table 5.2: Annual Capacity Payment Sum 2018 (C2 Calculation)

Year	BNE (€/kW/yr)	Capacity Req (MW)	ACPS (C2,€)
2018	63.51	7368	467,941,680

In summary, both ACPS values are as follows:

5.1 CALCULATION 1 (C1): THE ACPS 2018

To summarise, using the existing methodology and based on the 2017 ACPS figures, the ACPS 2018 (C1) is as follows:

The Proposed Annual Capacity Payments Sum (ACPS) for 2018 is €545,526,720

5.2 CALCULATION 2 (C2): THE ACPS 2018

To summarise, using the updated methodology and based on a reformation of the Total Investment Costs, the ACPS 2018 (C2) is as follows:

The Proposed Annual Capacity Payments Sum (ACPS) for 2018 is €467,941,680

6 COMPARISONS TO THE CAPACITY REMUNERATION MECHANISM

Market Participants will note that there are many parameters in this consultation paper that do not match necessarily to similar parameters that underpin the design of the new Capacity Remuneration Mechanism. In particular the capacity requirement value presented within this paper is not equal to the value of the requirement for the I-SEM CRM. The SEM Committee feel it pertinent to reinforce comments within a recent CRM paper[21] that discuss these differences.

In Capacity Remuneration Mechanism (CRM) detailed design decision 3 (SEM-16-039), the SEM Committee decided to introduce a bid limit which would apply to existing generators known as the Existing Capacity Price Cap (ECPC). All existing generators and interconnectors will be required to bid their full qualified volume into the transitional auctions and the T-4 auctions at a price no higher than the ECPC (specified in €/kW or £/kW), unless they apply for higher Unit Specific Price Caps (USPCs)~~.~~

In CRM Parameters and Auction Timings decision paper (SEM-17-022), the SEM Committee decided to set the ECPC at 0.5 x Net CONE and the Auction Price Cap at 1.5 x Net CONE. The CRM Parameters consultation paper (SEM-16-073) proposed changes to the Net CONE calculation, which were adopted in the decision paper (SEM-17-022).

The SEMC considers that the rationale of setting the ECPC and the APC is consistent with either of the Calculation 1 or Calculation 2 approaches in this consultation paper, while acknowledging that the BNE value in SEM-17-022 was set using the methodology consistent with calculation 1. The Parameters decision paper (SEM-17-022) described how the ECPC performs two key functions, and how the level of the ECPC needs to reflect these two key functions. Firstly, it limits the ability of generators with market power, but with low NGFCs to exercise their market power through making high offers. Secondly it provides a filter to ensure that only those USPC applications which the RAs need to scrutinise (because they may have a material impact on the clearing price or pay-as-bid prices) are scrutinised.

The value of the ECPC as set out in the Initial Auction Information Pack (AIP) is €41,060 MW per year (published on SEMO website). The auction price may clear above the ECPC level if capacity not subject to the ECPC (such as new entry or capacity with a USPC) is successful in the auction.

Since the ECPC and the APC are caps on bids that can be submitted by existing capacity (unless they request a Unit Specific Price Cap) and new capacity respectively, they are set at a level to promote competition and protect consumers, rather than as an expectation as to what the CRM auction

[21] §9.2, *I-SEM Capacity Remuneration Mechanism: Proposed Methodology for the Calculation of the Capacity Requirement and De-rating Factors* https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-051a%20Appendix%201%20TSOs%20Capacity%20Requirement%20and%20De-rating%20Factors%20Methodology.pdf

clearing prices may be. In addition, these values include methodological issues that arose as a result of the move from the SEM to the I-SEM, and will apply in general to all I-SEM CRM auctions. These adjustments reflect the introduction of design features such as de-rating, Administered Scarcity Price (ASP) and the Reliability Option (RO), and are described in section 6.2.7 of CRM Parameters consultation paper (SEM-16-073).

The SEM Committee wish to note that the observed differences with respect to the capacity requirement are due to the fact that the methodology employed in the CRM paper determines a de-rated capacity requirement rather than the *installed* requirement, with notional outage rates, determined for the Annual Capacity Payment Sum. Differences are also due to the provision of reserve within the CRM requirement; the CPM makes no provision for this.

7 Fixed, Variable and Ex-Post Proportions (FCPPy, VCPPy & ECPPy) FOR 2018

7.1 INTRODUCTION

The SEM Trading and Settlement Code places a requirement on 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 $0 \leq FCPPy \leq 1$;
- Ex-Post Capacity Payments Proportion (ECPPy), such that $0 \leq ECPPy \leq (1-FCPPy)$

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:

$$VCPPy = (1 - FCPPy - ECPPy)$$

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:

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

7.2 PROPOSED SETTINGS

For the Trading Year 2018 the RAs intend to consult on the payment proportions. The SEM Committee approved fixing these proportions for 2016 and 2017 in the Final Decision paper on ECPP and FCPP published in November 2015.

The RAs therefore invite participants to express their views on the above proportions, for the 2018 Trading Year.

8 VIEWS INVITED

Views are invited regarding all aspects of the proposals put forward in this Consultation Paper, with particular focus on the preferred method Stakeholders would like to see employed in the calculation of the ACPS 2018.

For ease of reference, Stakeholders should refer to the below scenarios when responding to this paper.

Reference	Scenario	ACPS 2018
Calculation 1 ("**C1**")	Existing ACPS method	€ 545,526,720
Calculation 2 ("**C2**")	Alternative method keeping EPC costs separate	€ 467,794,320

Responses to this paper should be addressed (preferably via email) to Kevin Baron at kevin.baron@uregni.gov.uk by **5pm on 4 August 2017**.

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 - ACPS FOR PREVIOUS TRADING YEARS

The annualised fixed cost of a BNE Peaking Plant is multiplied by Capacity Requirement resulting in the Annual Capacity Payments Sum (ACPS). The values for this calculation on an historical basis are presented in the table below.

Table A.1: Historical Annual Capacity Payment Sums and annualised Fixed Costs

Year	BNE annualised Fixed 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	7046	574,953,600
2016	72.82	7070	514,837,400
2017	70.99	7267	519,227,150
2018 (C1)[22]	74.04	7368	545,526,720
2018 (C2) [23]	63.51	7368	467,941,680

[22] Proposed value.

[23] Proposed value.

10 APPENDIX 2- DEMAND FORECAST

TableA2-1: Median Demand Forecast[24]

Median	Calendar year TER (TWh)						TER Peak (GW)			Transmission Peak (GW)		
Year	Ireland		Northern Ireland		All-island		Ireland	Northern Ireland	All-island	Ireland	Northern Ireland	All-island
2015	27.6	2.9%	9.05	0.0%	36.7	2.2%	5.03	1.74	6.77	4.91	1.72	6.59
2016	28.2	2.0%	9.06	0.1%	37.3	1.6%	5.11	1.74	6.77	4.99	1.72	6.67
2017	28.7	1.9%	9.07	0.2%	37.8	1.4%	5.19	1.75	6.86	5.08	1.73	6.75
2018	29.6	3.0%	9.09	0.2%	38.7	2.3%	5.31	1.75	6.98	5.19	1.73	6.87
2019	30.3	2.6%	9.13	0.4%	39.5	2.1%	5.42	1.76	7.10	5.30	1.73	6.99
2020	31.2	2.8%	9.17	0.4%	40.4	2.3%	5.52	1.77	7.20	5.40	1.74	7.09
2021	31.8	2.0%	9.21	0.4%	41.0	1.5%	5.62	1.77	7.26	5.49	1.75	7.15
2022	32.4	1.8%	9.24	0.4%	41.6	1.5%	5.66	1.78	7.30	5.53	1.75	7.18
2023	32.9	1.6%	9.28	0.4%	42.2	1.3%	5.68	1.79	7.33	5.55	1.76	7.21
2024	33.4	1.6%	9.32	0.4%	42.8	1.4%	5.69	1.79	7.34	5.56	1.77	7.23
2025	33.7	1.0%	9.36	0.4%	43.1	0.8%	5.70	1.80	7.42	5.57	1.77	7.30
2026	34.2	1.3%	9.40	0.4%	43.6	1.1%	5.77	1.81	7.49	5.64	1.78	7.37

[24] Generation Capacity Statement 2017-26 http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf