Single Electricity Market

CPM Medium Term Review

Final Decision Paper

6th March 2012

SEM-12-016

1 EXECUTIVE SUMMARY

1.1 INTRODUCTION

At the start of the CPM Medium Term Review 10 Work packages were decided upon:

- Work Package 1 - Historical Analysis of CPM
- Work Package 2 - Review of Capacity Requirement
- Work Package 3 - Deduction of IMR & AS & BNE Peaker Plant Options
- Work Package 4 - Best New Entrant (BNE) Peaker Plant Fuel Options
- Work Package 5 - Exchange Rate for CPM
- Work Package 6 -Treatment of All Generator Types in CPM
- Work Package 7 - BNE Calculation Methodology
- Work Package 8 - Incentives for Generators
- Work Package 9 - Timing & Distribution of Capacity Payments
- Work Package 10 - Impact of CPM on Customers

Nine responses were received for SEM-10-046 (Work Package 1 -5), sixteen for SEM-10-068 (Work Package 7) and 22 received for SEM-11-019 (Work Package 6 onwards). Two responses were marked Private and Confidential. These Discussion papers can be found on the http://www.allislandproject.org/.[1] The Draft Decision Paper (SEM-11-088) was published on November 2011. In that paper the SEM Committee stated its proposed decisions and asked for comments. Key highlight points from the CPM Medium Term Review Draft Decision Paper were:

- The current CPM is generally working well and that there is no compelling need to make major changes to the current design and methodology.
- The SEM Committee do not believe that the design of the distribution allocation should be materially changed.
- The SEM Committee believes that the current 30%, 40% and 30% ratio of respectively the Fixed Ex-ante, Variable Ex-Ante and Variable Ex-Post weighting components gives the appropriate balance between a short term signal to provide the required capacity during periods of tight capacity margin, and the longer term certainty over capacity revenues for generators.
- The FOP % in the Capacity Requirement calculation should be increased to 5.91%.

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[1] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=31822151-f6da-4f5a-9fba-61739dd35f98

- Infra Marginal Rent (IMR) will be deducted from the BNE Cost of the Annual Capacity Payment Sum (ACPS) on an annual basis.
- In the BNE calculation Methodology Option 5 will be introduced to calculate the BNE in 2013 and keep the BNE Peaker Cost (€/kW/yr) in place for a 3 year period, with a level of indexing in 2014 and 2015. The Capacity Requirement will be recalculated annually.
- SEM Committee were recommending increasing the Flattening Power Factor (FPF) to 0.5%.

Views were invited regarding any and all aspects of the draft proposals put forward in the draft decision paper. The following section summarises the main comments received regarding the main elements for these proposed decisions and a final SEM Committee decision is presented on the CPM Medium Term Review.

This paper reports on the comments of the CPM Medium Term Review Draft Decision Paper (SEM-11-088) and gives the SEM Committee's final decision on the matters covered therein, i.e. The Forced Outage Probability, the Infra Marginal Rent Deduction and the consistency of the calculation for a number of years.

There are no changes from the proposals contained in the draft decision. The proposals put forward in the Draft Decision paper will be implemented in the 2013 determination of the Best New Entrant Fixed Cost (BNE FC) and the Annual Capacity Payment Sum (ACPS).

The main outputs of the CPM Medium Term review will be;

- Infra Marginal Rent (IMR) will be deducted from the BNE,
- The FOP % in the Capacity Requirement calculation will be increased to 5.91%,
- The BNE will be calculated in 2013 and the BNE Peaker Cost (€/kW/yr) will be in place for a 3 year period.

Several elements both domestic and European could also impact the ACPS during this 3 year period. In 2012 the TSOs in cooperation with the Regulatory Authorities will be undertaking a Systems Services Review (DS3[2]) multi-stage consultation process. The proposals / services identified may impact the AS revenues earn by the BNE over the 3 year period. The Regulatory Authorities reserve the option to review the AS reduction in future years of this period, if they believe it is appropriate to do so.

The European Integration timelines may also impact the 3 year timeline. The Regulatory Authorities will review the CPM BNE calculation again in the spring of 2015 to determine if the timeline will be extended based on the latest European model.

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

2 OVERVIEW OF RESPONSES

2.1 BACKGROUND

The Regulatory Authorities, on behalf of the SEM Committee, reviewed the current process used for distributing the capacity pot among generators and the calculations for payments by suppliers. The SEM Committee considers the CPM as a key feature of the SEM design and as extensive analysis and consultation on this topic took place prior to SEM Go Live, the concept of the CPM should remain in place. The SEM Committee's intention is that the correct signals and appropriate incentives or rewards are inherent in the design. In particular the SEM Committee are mindful that CPM should reward plant and capacity in accordance with its performance and provide signals for new entry/investment and exit if required.

The main purpose of this review was to examine if the current design of the CPM can be further improved to optimally meet the objectives of the CPM. Nine responses were received for SEM-10-046 (Work Package 1 -5), sixteen for SEM-10-068 (Work Package 7) and 22 received for SEM-11-019 (Work Package 6 onwards). Two responses were marked Private and Confidential. These Discussion papers can be found on the http://www.allislandproject.org/.[3]

Following a review of these responses the SEM Committee published a Review Draft Decision Paper (SEM-11-088) regarding its proposed approach to CPM Medium Term Review on 15th November 2011[4]. This paper sets out the SEM Committee's decision on the proposed decisions identified in the Draft Decision Paper. The main body of the paper focuses on each of the issues in turn and presents the SEM Committee's draft conclusions.

2.2 RESPONSES TO THE DRAFT DECISION PAPER

14 Responses to the Draft decision paper were received from the following parties and are published on the All-Island Project website along with this Decision Paper.

AES	ESB Power Generation
Bord Gáis Energy	ESB Wind Development
Bord na Móna	IWEA
EirGrid	Lumcloon Energy
Endesa	NEA Ireland
Enercomm International	Power Procurement Business (PPB)
Energia	SYNERGEN

One response was rejected as it was received over one month after the deadline for public comment on Friday 13th Jan 2012. The Regulatory Authorities have reviewed all the responses to the CPM Review and most respondents would not support any substantive changes to the CPM, given the changes in the investment environment and the EU legislative environment for energy. Overall, there was a positive response to the Forced

[3] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=31822151-f6da-4f5a-9fba-61739dd35f98

[4] http://www.allislandproject.org/GetAttachment.aspx?id=df23babb-e578-4c2c-abfa-802edf79f4fa

Outage Probability (FOP) proposal and a negative response to the Infra-Marginal Rent (IMR) Deduction proposal contained in the draft decision paper, as detailed below.

2.2.1 FORCED OUTAGE PROBABILITY (FOP)

The SEM Committee proposed using a targeted FOP value used in the future capacity requirement calculation of 5.91%. This was derived based on an analysis of historical SEM forced outage rate information provided by the TSOs. Thirteen respondents commented on the Forced Outage Probability (FOP) section of the draft paper. Respondents to the draft decision paper all generally supported the proposal to increase the targeted FOP from 4.23% to 5.91%. They stated that they were in favour of the proposed change of the Forced Outage Probability to 5.91% and that they consider that this is a more realistic figure than in previous years.

Summary of comments received:

Several respondents mentioned that there is no information or transparency on, the derivation of the new "target" FOP and that they would consider that a rolling average (over 3 to 5 years) of historic actual forced outage rates would be more appropriate, particularly as increased cycling resulting from higher wind penetration is likely to result in higher levels of FOP. Some respondents requested that SEM Committee establish a transparent FOP mechanism based on the historical SEM FOP which can be consistently applied and therefore predicted by investors. They requested that it would be desirable to have the methodology used in arriving at this revised figure of 5.91%.

A few respondents stated that while the proposed 5.91% target FOP value is welcome it is not well founded in practice or justifiable as a target value. This figure is still significantly below the average for the past 5 years and needs to be in the region of 8%-9% to reflect forced outage rates observable in practice.

Some respondents did not support a target FOP rate. They would instead support the adoption of a 3 year historic rolling average rate (including all generation units and the interconnector) as the FOP input into the capacity requirement calculations. One respondent stated that over time, this would provide the most accurate reflection of actual system conditions and margin requirements, even if there are some temporal inaccuracies. It is implausible that any generators would have any rationale to distort this figure given the commercial implications of being unavailable. The use of full historic FOR (Forced Outage Rate) data is thus transparent, accurate and neutral in its application and should be adopted as the approach. They also stated that should major elements of the CPM be fixed over a 3 year period, this would require that the rolling average FOR element of the FOP assumption was not one of these fixed elements.

2.2.2 INFRA MARGINAL RENT (IMR) DEDUCTION

The SEM Committee proposed that IMR will be deducted from the BNE on an annual basis through the following calculation:

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

They had stated that this method will reduce the level of volatility and potential uncertainty that the current IMR deduction gives. Thirteen respondents commented on the Infra Marginal Rent section of the draft paper. Eleven respondents were against the SEM Committee proposal of deducting the IMR from the BNE calculation and two respondents welcomed the proposal.

Summary of comments received:

Two respondents stated that they welcome the introduction of the IMR formula for determining the IMR revenue in the BNE calculation as it will remove much of the volatility from the BNE calculation. They also stated that the current arrangement whereby the IMR is low in a year when there is high capacity margin and hence results in a higher capacity payment – and vice versa, when there is a low capacity margin – it is entirely contrary to economic principles; a low capacity margin should result in a higher capacity payment and vice versa.

However, the majority of remaining respondents were strongly against the proposal of introducing the IMR formula in the BNE calculation. Several respondents commented that while the SEM Committee have decided 'to pursue its preferred option'; this option, as per the calculation in Table 7.3 of the Draft Decision paper, results in a net reduction of 9-10% of the ACPS, which would have a considerable impact on generator capacity payment revenues. They suggested that such a deduction, in what is a regulated income, can hardly be described as a "minor change." One respondent considered that the change to the calculation of IMR proposed constituted a fundamental change to the design of the Capacity Payment Mechanism.

Several respondents stated that that there is no fundamental market design reason behind deducting theoretical IMR from the ACPS ostensibly to minimise non-existent volatility, and would urge the Regulatory Authorities not to implement Option 2. Others did not believe that the underlying rationale regarding the volatility of the IMR had been adequately justified or illustrated as there is no volatility problem to resolve.

One respondent commented that they accept that while there is potential to earn IMR. The current modelling is a more accurate projection of what a peaker might reasonably earn in IMR (and what investors would base financing estimates on in reality), and therefore a more reasonable input into the capacity payment calculation as per the stated intentions of the CPM design and methodology.

Several respondents commented on the determination of "excess IMR" earned during hours of lost load "at equilibrium". They highlighted that the suggestion of "excess IMR" is incorrect. They also indicated that, market commentators opine that the ideal situation where supply and demand always reaches equilibrium requires a number of conditions to be met which in practice cannot be met in a market with, for example, price caps. As the SEM structure and design does not allow the SMP to reach VOLL due to price caps, this extinguishes the second of the SEM Committee's stipulated characteristics of a market in equilibrium and stated that in fact the very requirement for a CPM itself contradicts the equilibrium theory.

One respondent stated that the current approach calculates the IMR for deduction based on a Plexos dispatch model showing what hours a BNE peaker is forecast to run in the incoming tariff year. The effect for the last 2 years has been zero IMR, on the basis that there has been virtually no requirement for peakers to run, and when they do run they set the price, and therefore do not receive any infra marginal rent. They stated that Option 2 uses a theoretical formula, based on PCAP that does not correspond to reality. This proposal is contrary to the prior decision of the SEM as published in SEM 07-187, which stated that IMR should be calculated on the basis of the 'current competitive system state' and not from an artificial scenario. To-date PCAP has never occurred in SEM. It is unlikely that a BNE peaker would be financed on the basis of a theoretical revenue calculation that has never occurred in practice in the 4 years of SEM operation.

Several respondents stated that the peaking unit would be the marginal plant and therefore does not earn any infra marginal rent. Some respondents believed that the status quo should be retained in the calculation of the

IMR reduction. If it is to be a signal to investors, IMR should be deducted but only when it is reasonably expected to earn IMR. They believe that the current Plexos modelling is the best estimate of plant running for the next year and should continue to be used to forecast whether the BNE will earn IMR. They also stated that the most recent modelling does not envisage that the BNE will earn IMR (on the basis that it will be at best the marginal plant and therefore setting the SMP) and therefore reducing the capacity pot by a theoretical IMR would undervalue capacity in the market.

Some respondents considered in their view the administratively derived IMR, as per Option 2 in SEM-10-046, is unjustified, incorrect, totally unrealistic, and very damaging to the effective functioning of the CPM. They stated that this proposal must be rejected to retain credibility in the CPM.

Several respondents also commented that they did not believe that their position on these decisions were not accurately categorised in the Draft Decision Paper.

2.2.3 THE BNE WILL REMAIN CONSTANT FOR 3 YEARS.

The Regulatory Authorities proposed that the 2013 BNE calculation will be completed using the current methodology with the FOP increased and the IMR deducted. For the subsequent two years (2014 and 2015) all BNE elements of the BNE calculation will remain fixed and have a level of indexing applied. The Capacity Requirement will continue to be calculated on an annual basis in conjunction with the TSOs as will the T&S Code parameters. Twelve respondents commented on the fixing of the BNE for a number of years. The majority of respondents generally were very supportive of fixing the BNE of a number of years. They see the proposal to fix elements of the BNE FC calculation for 3 years as having merit in reducing the potential for volatility, within such a three year period.

Summary of comments received:

Three respondents were not supportive of the option of fixing for three years; one respondent commented that it is their preference to have a five-year rolling average which reflects actual costs. Another respondent stated that while the concept of fixing certain elements of BNE price determination has its attractions, there was no actual analysis of the impact of fixing (with indexation) certain elements of the BNE price and therefore it was impossible to comment on the impact and materiality of such a freezing approach on the boundary step change that could occur at the end of the period. As a result, the value of “fixing” is un-quantified and merely conceptual.

Another respondent commented that given the stated rationale for the 3 year timeline to be also cognisant of 2016 European Integration timelines, they strongly suggest extending the fixed duration further, until at least 31 December 2016 as this will dovetail better with the end 2016 deadline for SEM compliance with the EU Target Model. One respondent stated that this 3 year timeframe does not provide the level of certainty required to facilitate new investment in flexible plants that are likely to be required to provide the necessary system services to facilitate delivery of Government 2020 targets.

Several respondents supported the added stability and certainty that this option brings over the existing regime, but had concerns regarding step changes to the CPM. Another respondent stated that they would strongly encourage stability in the CPM for the next 3 years, but it needs to be on a realistic and sustainable basis. One respondent stated that they support the proposal that the BNE would remain constant for three years, adjusted for inflation. This feature would provide existing generators and new investors with stability and certainty, both objectives of the CPM.

Some respondents commented on the interaction of the three year proposal and the issue with fixing certain elements of the BNE calculation, in particular the WACC. One respondent stated that, only the key volatile elements of the BNE fixed costs should remain static for three years, e.g. WACC, while the less volatile elements would continue to be consulted on annually to continue market reflectivity. Clarification is however required as to whether the WACC is a factor that will remain fixed under the Draft Decision.

Several respondents also stated that they were concerned that the continued use of the UK WACC as the range for the BNE WACC, as it does not reflect the reality of an investor contemplating an investment in the SEM. One respondent stated that the UK WACC does not reflect the risk of the geographical separation of NI from mainland GB, the SEM, the fact that energy policy is devolved to the NI Assembly and the unique circumstances of investing in a market that operates across two separate legal jurisdictions. They commented that this is further compounded by the fact that, since NI makes up only about 25% of the SEM total electricity requirement, the ROI is by far the dominant influence and an investor contemplating an investment in NI will place significant weight on the economy and political stability of the ROI.

Another respondent stated that they would consider that an investor in the all-island market would take into account the all-island economic situation (rather than Northern Ireland or Ireland separately and certainly not the UK) when calculating a WACC. A blended WACC would be more appropriate for the BNE.

2.2.4 TIMING AND DISTRIBUTION OF CAPACITY PAYMENTS

In the Draft Decision paper for 2013 the SEM Committee recommended to increase the Flatting Power Factor (FPF) to 0.5%. This is consulted upon on an annual basis as part of the Trading and Settlement Code Parameters consultation process and will be reviewed for the 2013 capacity year in the summer of 2012. The SEM Committee have decided that other elements in the distribution (such as the fixed, variable and ex-post allocation) will, remain the same. Twelve respondents commented on the distribution and timing and the FPF. Four respondents were in favour of increasing the FPF, whereas seven respondents were against and one respondent noted the increase and will wait the paper in the summer from the TSOs to respond accordingly.

Summary of comments received:

Several respondents supported the increase in the FPF and stated that as these are consulted upon annually there is ongoing opportunity to change them if warranted. One respondent stated that the mechanism has to date probably given excessive weighting to predictability of payments over the year as contrasted with cost (or value) reflectivity and the draft recommendation goes some way towards addressing that imbalance. Another respondent also supported the draft decision to increase the FPF to 0.5 but only in conjunction with the reduction of the variable capacity payments proportion to 0%. They stated that if the variable proportion is set at a value other than 0% they would recommend retaining a value of 0.35. The change to the FPF in isolation may not have the desired effect. It may result in a shift in payments across technology types therefore it requires consideration in terms of the overall cost to the consumer. Recent studies by the TSO indicate a transfer of monies between technology types as a result of increasing the FPF to 0.5. Most respondents welcomed the fact that while this is a proposed recommendation to increase the FPF, they will have the opportunity to review the TSOs proposal in the summer of 2012.

Seven respondents were against the SEM Committee's intention to increase the FPF from 0.35 to 0.5. Several respondents commented that the proposed increase would result in greater capacity payment volatility, and more unpredictable capacity payment revenues for all generators, they stated that this is contrary to the price stability objective of the CPM.

One respondent stated that while they understand the SEM Committee's desire to increase the short-term capacity shortage signal they remain of the view that in reality it will make very little difference to generators. Generators always wish to be available. However they will have periods of unavailability due to planned and forced outages. By definition, forced outages are unplanned and therefore outside of the generator's control. Even with planned outages generators have limited ability to alter these due to compliance with manufacturing guidelines and warranties, statutory insurance inspections and the requirement to notify outages to the TSO at regular prescribed intervals. Thus there is generally a long lead time when scheduling outages and limited opportunity to alter them. Therefore even if the FPF did highlight periods of low margin there is very little action that a generator can take other than perhaps rescheduling a non-urgent, short-term, ad-hoc outage.

Another respondent stated that an increase in FPF increases the volatility of Ex Post capacity payments. It also increases the exposure of not being available and has the effect of putting more capacity payments into periods when the wind does not blow. Such an increase would affect the revenue risk of all generators but particularly wind farm generators. They were opposed to increasing the FPF, as this is particularly discriminatory against wind capacity and they also note that increasing risks for investors at this stage is particularly unsatisfactory considering the uncertainty that is currently faced by investors as a result of regional integration. One respondent also stated that increasing the volatility of the ex-post CPM revenue volatility can only make the interfacing of the Irish wholesale market with the wider European markets more difficult and will likely result in a less efficient outcome.

3 SEM COMMITTEE DECISIONS

Following a review of the responses, most have commentated that the European / Economic landscape has changed dramatically since the review began. In addition to the changes in the investment environment, the legislative environment for energy is undergoing significant change. Given the significance of these changes and this uncertainty, the majority of respondents would not support any substantive changes to the CPM. Taking account of the comments received to the draft decision paper (see section 2) and latest relevant developments (which were discussed in the draft decision), the SEM Committee now sets out below its decisions in relation to the SEM Capacity Medium Term Review. There are no changes from the proposals contained in the draft decision. The key SEM Committee decisions on the Capacity Medium Term review are summarised below.

3.1 FORCED OUTAGE PROBABILITY (FOP)

The increase in the Forced Outage Probability (FOP) element used within the capacity requirement calculation was welcomed by the majority of respondents, though some respondents stated that this figure is still significantly below the average for the past 5 years and needs to be in the region of 8%-9% to reflect forced outage rates observable in practice. While the concerns expressed by respondents are noted, it remains the view of the SEM Committee that it is essential that the CPM does not over value capacity. The SEM Committee are of the view that a targeted FOP should continue to be used in the calculation.

The previous FOP used in the calculation was defined as 4.23% in the paper 'Methodology for the Determination of the Capacity Requirement for the Capacity Payment Mechanism Decisions Paper (SEM-07-13). This was based on the weighted average FOP for Northern Ireland plant for the period 2002 to 2006.

For the revised FOP calculation the Regulatory Authorities reviewed the Historical All Island FOPs from the start of the SEM. Within this calculation several plant types were excluded to determine the revised targeted FOP. Peat, Hydro and Pump units were excluded; discontinued plant and new plants commission in 2010 were also excluded from the analysis. The proposed revised targeted FOP has been calculated to be 5.91%.

The SEM Committee recognise that revised FOP of 5.91% is lower than the average FOP on an All Island basis; however it should be noted that reflecting the poor performance of plant in the determination of the Capacity Requirement will effectively provide compensation to units which perform poorly. As previously stated one of the objectives of the CPM is to provide an incentive for improvements in plant availability and the Regulatory Authorities believe that by continuing to maintain the Capacity Requirement against a target FOP value, generators will continue to be provided with an incentive to improve their performance toward the target level. The SEM Committee will review the targeted FOP again for the 2016 Calculation.

3.2 INFRA MARGINAL RENT (IMR) DEDUCTION

The SEM Committee have decided that IMR will be deducted from the BNE through the following calculation –

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

This method would heavily 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 Market Price Cap (PCAP) and Generation Security Standard (GSS /Outage Time) and so the deduction should be able to be forecast by investors with reasonable accuracy. The only ‘floating’ variable is the bid price of the BNE unit, which will be driven by prevailing fuel prices (distillate in the case of a distillate-fired plant for example).

It had been suggested previously, from respondents, that infra-marginal rents should not be deducted from the BNE price at all, as some respondents have stated it conflicts with the underlying economic equilibrium theory of the BNE unit being marginal in an equilibrium setting. The Regulatory Authorities have on previous occasions stated that the deduction is necessary in order not to over-remunerate plant. As in 2007, these rents accrue due to the current sub-equilibrium settings of the plant mix on the island and therefore, the Regulatory Authorities consider that it is correct that they are accounted for. In the underlying theory of the CPM it is assumed that the market is in equilibrium with a Generation Security Standard and therefore the Regulatory Authorities are interested in establishing the IMR resulting from the current system state.

Several comments were received regarding the assumption that at “equilibrium” the BNE will earn IMR. The equilibrium price (SMP), should ideally be equal to the generation marginal unit, which except in the case of a scarcity in the supply of generation resources, should also equal the system’s marginal production cost. At times of scarcity, using the Generation Security Standard of 8 hours loss of load the system and considering the Trading and Settlement Code Market Price Cap, all available plant (including the BNE) will have the opportunity to earn IMR at a SMP equal to PCAP. These plants will have the opportunity to earn IMR within those hours. Hence, the SEM Committee is of the view that it is appropriate that this revenue should be deducted from the BNE Peaker costs. The SEM Committee believes that this methodology is consistent with the theory supporting the current BNE calculation.

At a scarcity event, (during these 8 hours) there is excess demand at which the price equals the marginal cost of the last generating unit but supply can not be provided by all the generation units. The price (which reflects the value that consumers will place on having the extra supply) will increase to PCAP and therefore the scarcity price will exceed the marginal cost of the BNE. At market equilibrium the price/ rents earned by the generating units during the scarcity event will cover all the operating costs of all resources and provide additional revenue up to PCAP. The BNE therefore has the potential to earn IMR revenue at equilibrium during these scarcity event hours.

The Capacity Payments theory also dictates that in the assessment of the cost of the BNE peaking plant, an expectation of assumed profits from the energy and AS market that such a plant will earn should be deducted from the fixed cost figure of the plant. The BNE would also be expected to earn a profit from the energy market if it has a lower avoidable cost that existing plant and so displace the existing plant from the merit order, therefore deprive some profit from the SMP during these scarcity events.

Several respondents also commented that they did not believe that their position on these decisions were not accurately categorised in the Draft Decision Paper. The Regulatory Authorities wish to correct any miss-categorisation and welcomed the discussion with participants regarding the classification of their comments.

The inclusion of IMR deduction will help reduce market uncertainty and reduce risk premiums to investors compared to an energy only market. This option would be transparent, predictable, simple to administer and reduce regulatory risk from year to year calculations. The SEM Committee will include this process in the 2013 BNE Calculation consultation process.

3.3 THE BNE WILL REMAIN CONSTANT FOR 3 YEARS.

Based on the lessons learned from analysis of various international experiences, the Regulatory Authorities consider that a 'Component Period Horizon' of 3 years can bring some stability and certainty to the volatility in the capacity pot year on year. There is merit in a commitment period greater than one year in that capacity providers will have greater certainty as to remuneration for their capacity provision which would provide the capacity providers, particularly new entrants, greater certainty and ability to respond. Elements such as the Technology Options / EPC investment costs and region will remain constant but indexed over the following two years.

Several respondents also stated that they were concerned that the continued use of the UK WACC as the range for the BNE WACC. As the 2013 calculation now will have an impact on the ACPS for the next 3 years, increased focus will imply on the elements that will determine the 2013 ACPS. The methodology for determining the 2013 BNE will remain unchanged, all elements including the WACC will remain fixed over the 3 year horizon and the final BNE Peaker Cost (€/kW/yr) will be indexed in subsequent calendar years.

For indexing, the €/kW/yr value will be determined by taking its values in the preceding year and up-rating it by applying the year-on year movement in the Harmonised Index of Consumer Prices (HICP) of the region that the WACC / economic parameters are applied.[5] For example, if the BNE is in the North and a UK WACC is used then the UK HICP weighing will be used to index the €/kW/yr value. Future forecasts for the UK economy[6] can be obtained from the UK Treasury, an estimated 2% increase in UK HICP from 2013-2014 would result in over €10m being added to the ACPS in 2014. Other elements such as the Capacity requirement and the T&S code Parameters will be continue to be calculated on an annual basis in conjunction with the TSOs.

Within the BNE calculation the assumptions in the 2013 consultation paper will be based on the latest published information and if updated final tariffs /rates relating to the 2013 BNE year are available ahead of a decision on the cost of the ACPS, the values in the calculations will be adjusted accordingly to reflect these. Regarding the economic parameters, the Regulatory Authorities will be asking the BNE consultants to provide the SEM Committee with additional information regarding the WACC. The SEM Committee will review this information and determine the methodology to be implied in the 2013 BNE consultation paper.

Some respondents commented that given the stated rationale for the 3 year timeline to be also cognisant of 2016 European Integration timelines, and one respondent suggested extending the fixed duration further, until at least 31 December 2016 as this will dovetail better with the end 2016 deadline for SEM compliance with the EU Target Model. The Regulatory Authorities will review the CPM BNE calculation again in the spring of 2015 to determine if the timeline will be extended based on the latest European model.

3.4 ANCILLARY SERVICES DEDUCTION

The Regulatory Authorities will continue to work with the Transmission System Operators (TSOs) to define additional Ancillary Services (AS) if required and the value of these services to the system as highlighted in the

[5] The sources for the data on HCIPs are the Central Statistical Office (CSO) in Ireland and the Office for National Statistics (ONS) in the UK. Ireland -http://www.cso.ie/en/statistics/prices/consumerpriceindex/ UK - http://www.ons.gov.uk/ons/publications/all-releases.html?definition=tcm%3A77-22462

[6] http://www.hm-treasury.gov.uk/forecasts

Harmonised All-Island Ancillary Services Policy decision paper (SEM/08/013[7]). The TSOs also have the ability to suggest new or modified services if considered of benefit to the efficient operation of the system. The Regulatory Authorities continue to believe that the responsibility of incentivising the type of operational generation capacity required maintaining system security and reliability falls within the remit of ancillary service payments. As previously stated the Regulatory Authorities believe that the CPM is tailored to ensure that it would pay a Best New Entrant (BNE) peaker generator at a sufficient rate to cover its long run costs, given forward looking estimates of its running and all its other revenues, including ancillary services revenues.

In 2012 the TSOs in cooperation with the Regulatory Authorities will be undertaking a Systems Services Review (DS3) 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 AS revenues earn by the BNE over the 3 year period. The Regulatory Authorities reserve the option to review the AS reduction in future years of this period, if they believe it is appropriate to do so.

3.5 TIMING AND DISTRIBUTION OF CAPACITY PAYMENTS

The SEM Committee continues to believe that the current 30%, 40% and 30% ratio of respectively the Fixed Ex-ante, Variable Ex-Ante and Variable Ex-Post weighting components gives the appropriate balance between a short term signal to provide the required capacity during periods of tight capacity margin, and the longer term certainty over capacity revenues for generators.

In the Draft decision paper the SEM Committee indicated their preference to increase the Flatting Power Factor (FPF) to 0.5. Twelve respondents commented on the distribution and timing and the FPF. Four respondents were in favour of increasing the FPF whereas seven respondents were against and one respondent noted the increase and will await the paper in the summer from the TSOs and respond accordingly. In September 2012 the Regulatory Authorities will be publishing the TSO’s Proposed Value for the Flattening Power Factor for the year 2013. The SEM Committee will reserve its decision until the outcome of this report is known. The proposed FPF change, if any, will be published at this time. This will allow respondents the opportunity to comment on any potential changes to the FPF that will affect the 2013 distribution of the Pot.

Choosing an appropriate value for the FPF is a matter of striking an appropriate balance between retaining sufficient volatility to signal the need for availability in times of low margin and avoiding excessive volatility that would render the mechanism highly unpredictable. The timing and distribution allocation and the FPF are reviewed on an annual basis and these will continue to do so in the near future.

[7] http://www.allislandproject.org/GetAttachment.aspx?id=20252281-e52a-4ae5-a2a4-102c8546b045

4 CONCLUSIONS

As highlighted in the draft decision paper the SEM Committee wishes to continue to satisfy that the correct signals and appropriate incentives or rewards are inherent in the design, so as to meet its objectives optimally. In particular the SEM Committee are mindful that CPM provides signals for new entry/investment and should reward plant and capacity in accordance with its performance.

Changes to the SEM and its high level design are being investigated in the European Market Integration work stream.[8] Future elements of the CPM will be discussed in the context of proposed changes to be progressed within the European Market Integration work stream. With this in mind the SEM have chosen to fix the BNE calculation for 3 years, this will involve completing the 2013 calculation as normal and for the subsequent two years (2014 and 2015) all BNE elements of the BNE calculation will remain fixed and have a level of indexing applied.

The Regulatory Authorities will review the AS element in the future years of this period, if they believe it is appropriate to do so. The European Integration timelines may also impact the 3 year timeline. The Regulatory Authorities will review the CPM BNE calculation again in the spring of 2015 to determine if the timeline will be extended based on the latest European model.

The IMR of the BNE Peaker will be deducted from the 2013 BNE Peaker Cost (€/kW/yr) and the FOP % in the Capacity Requirement calculation will be increased to 5.91%.

The annual parameters affecting the T&S code elements of the CPM such as the Exchange Rate, the 30/40/30 split and the FPF are consulted on annually and will continue to be consulted on annually over the 3 year period. This will ensure that participants have every opportunity to influence the SEM / CPM development in line with the European guidelines / codes and to ensure that these parameters continuing to meet their intended objectives.

[8] http://www.allislandproject.org/en/TS_Current_Consultations.aspx?article=41f5681a-ef37-41ca-ab7d-7a1bdd7db385&mode=author