Single Electricity Market

CPM Medium Term Review

Draft Decision Paper

15th Nov 2011

SEM-11-088

1 CONTENTS

2 EXECUTIVE SUMMARY

Following a review of the responses, most have commented that the 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 where Ireland and Northern Ireland must comply with the Third Package and the emerging European Framework Guidelines and Network Codes. There are significantly different contexts that should be taken into account, notably, the emerging European Target Model, the penetration of renewables and adverse economic conditions. Given the significance of these changes and this uncertainty, the majority of respondents would not support any substantive changes to the CPM. The SEM Committee agrees with this position but will make minor changes to certain aspects of the CPM calculation.

2.1 FORCED OUTAGE PROBABILITY (FOP)

The targeted FOP value used in the future capacity requirement calculation will be 5.91%. This is derived based on an analysis of historical SEM forced outage rate information provided by the TSO's.

2.2 INFRA MARGINAL RENT (IMR) DEDUCTION

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)

This method will reduce the level of volatility and potential uncertainty that the current IMR deduction gives.

2.3 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 'Period Horizon' of 3 years can bring some stability and certainty to the volatility in the capacity pot year on year. 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.

2.4 TIMING AND DISTRIBUTION OF CAPACITY PAYMENTS

For 2013 the SEM Committee are recommending 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.

The SEM Committee have decided that other elements in the distribution (such as the fixed, variable and ex-post allocation) will, remain the same.

3 INTRODUCTION

In May 2005 the Regulatory Authorities (RAs) set out the options for the Single Electricity Market (SEM) Capacity Payment Mechanism (CPM)[1]. In the paper the Regulatory Authorities indicated their proposal to develop a fixed revenue capacity payment mechanism 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 (TSC).

On 8th April 2009 the SEM Committee published a discussion paper (SEM-09-035)[2], documenting the scope of work that they proposed to carry out in relation to a medium term review of the Capacity Payment Mechanism.

The Regulatory Authorities, on behalf of the SEM Committee, intend to review 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 intension is that the correct signals and appropriate incentives or rewards are inherent in the design. 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.

On 17 November 2009 the SEM Committee (SEMC) published a CPM Medium Term Review Information Paper (SEM-09-105)[3], documenting the scope of work that the Regulatory Authorities plan to carry out in relation to a medium term review of the CPM. The main purpose of this review is to examine if the current design of the CPM can be further improved to optimally meet the objectives of the CPM.

The Objectives of the CPM were distilled in the paper 'Capacity Payment Mechanism and Reserve Charging High Level Decision Paper' (SEM-53-05) as:

- **Capacity Adequacy/ Reliability of the system**
  The CPM must encourage both new construction and maintain availability of capacity in the SEM. Security of the system, in both the long and short-term will be the core feature of any CPM.
- **Price Stability**
  The CPM should reduce market uncertainty compared to an energy only market, taking some of the volatility out of the energy market.
- **Simplicity**
  The CPM should be transparent, predictable and simple to administer, in order to lower the risk premium required by investors in generation. A complex mechanism will reduce investor confidence in the market and increase implementation costs.

---

[1] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?page=2&article=0e5940cb-4c5d-4e01-982d-2b3587c33d2d

[2] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=4dde96cc-fdda-458b-9a3c-dc4a00692ac5

[3] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=e8b5dd74-5be7-4dc6-a17d-20aadb247683

- **Efficient price signals for Long Term Investments**

  In theory it would be possible to incentivise vast amounts of capacity over and above that necessary for system security in the SEM, although the cost of implementing such a scheme may be unacceptable to customers. The CPM should meet the criterion in this section at the lowest reasonable cost. Revenues earned by generators should still efficiently signal appropriate market entry and exit.
- **Susceptibility to Gaming**

  The CPM should not be susceptible to gaming and, ideally, should not rely unduly on non-compliance penalties.
- **Fairness**

  The CPM should not unfairly discriminate between participants. An appropriate CPM will maintain reasonable proportionality between the payments made to achieve capacity adequacy and the benefits received from attaining capacity adequacy. Buyers in the SEM should pay in proportion to the benefits they receive.

The CPM should achieve capacity adequacy consistent with efficient energy market signals, and without interfering with the market forces that drive generation investment decisions other than those related to the provision of capacity reserves. It should not "double pay" generators. Overall prices should efficiently signal when, where and what types of new generators are required and efficiently signal when, where and what market exit is appropriate.

Ongoing development of the SEM and the CPM was always anticipated by the Regulatory Authorities during their design. It is judged that to date that the SEM is working well; however, there are known challenges. With this in mind, the SEM Committee do not wish to choose options that are disproportionately expensive or different to the current design relative to the benefits the changes would create.

Several market forces have undergone significant changes since the initial scope of the CPM Review.

- The Financial Investment Environment.
- The Legislative Environment for Energy – such as the Third Package and the Framework Guidelines and Network Codes.
- Regional Integration of European Electricity Markets.

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. Most respondents do not want to change the concept of the CPM but tweak some elements such as the inputs assumptions/conditions used in the annual calculation of the pot. The SEMC has taken these comments on board.

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 - 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/.[4]

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

Company	SEM-10-046 Work Package 1-5	SEM-10-068 Work Package 7	SEM-11-019 Work Package 6, 8, 9 and 10
AES		☑	☑
ART			☑
Bord Gáis Energy	☑	☑	☑
Bord na Móna	☑	☑	☑
EirGrid			☑
Endesa	☑	☑	☑
Enercomm International			☑
Energy Generation Infrastructure			☑
ESB International		☑	
ESB Power Generation	☑	☑	☑
ESB Wind Development		☑	☑
Forfás - Enterprise Ireland - IDA Ireland		☑	
IBEC		☑	
IWEA	☑	☑	☑
NEA Ireland			☑
NIE Energy Limited Power Procurement Business (PPB)	☑	☑	☑
Peaker Plant Investors Group (PPIG)		☑	
PHES Ltd			☑
Private and Confidential			☑
Private and Confidential			☑
RES		☑	
SSE Renewables			☑
SYNERGEN	☑	☑	☑
The Consumer Council	☑	☑	☑
Tynagh Energy			☑
Viridian Power & Energy	☑	☑	☑
Wartsila			☑
Total	**9**	**16**	**22**

Table 1.1 – Responses to the three discussion documents

This paper sets out the SEM Committee's response to the comments received and presents the draft conclusions of the SEM Committee in the matters addressed by the three discussion papers. The main body of the paper focuses on each of the issues in turn and presents the SEM Committee's draft conclusions. Views are invited regarding all aspects of the proposals put forward in this draft decision paper.

4 WORK PACKAGES 1 TO 5

The Discussion Paper SEM-10-046[5] (CPM Medium Term Review Work Packages 1 to 5 - Historical Analysis of CPM And Proposed Decisions) was published in July 2010 seeking views from interested parties and was made up of 5 work packages covering the following areas:

- 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 - BNE Peaker Plant Fuel Options
- Work Package 5 - Exchange Rate for CPM

9 responses were received from Bord Gáis Energy, Bord na Móna, Endesa, ESB PG, IWEA, NIE Energy Limited-Power Procurement Business (PPB), Synergen, The Consumer Council and Viridian Power and Energy (VPE).

5 WORK PACKAGE 1 - HISTORICAL ANALYSIS OF CPM

Work Package 1 looked at a historical analysis of the CPM and the Regulatory Authorities assessed the distribution of capacity payments on availability, particularly at times when capacity is needed most. Within this analysis, the following sections were reviewed;

- Distribution of payments based on Plant Type,
- Distribution of Payments Vs Margin,
- Time of Day Payments.

Five respondents commented on Work Package 1 - Historical Analysis of CPM

Summary of comments received:

In relation to the Plant Type analysis, a respondent commented that given the capacity factor of wind generation and that they are paid for capacity solely on generation, it is only fair that conventional generators, who are paid based on availability, are subject to rigorous testing, in order to verify this declared availability.

Another respondent commented that from the analysis in the paper, it is clear that payments are weighted to reward capacity for periods where the relative margin was at its lowest point during the month, regardless of the absolute level of the margin for the month in question. It should be safe to assume therefore that the mechanism will work appropriately, where the absolute level of the margin is at much lower levels. This gives confidence that the disbursement of capacity payments is giving the appropriate signals to generators to provide the capacity when it is most needed.

[5] http://www.allislandproject.org/en/cp_current-consultations.aspx?article=88df8ce4-9a8c-4694-b93b-2c52d3c9d89f

Two respondents commented on that the analysis only covered a short period of time and it would have been better to assess the full period since the start of the SEM. Another respondent stated that in the analysis, not only should the relationship between the margin and CPM payments be considered, but the relationship with SMP also needs to be examined to assess the extent to which CPM payments are correlated to SMP.

Another respondent commented that there is, by design, a trade off between the level of certainty given to generators with the fixed element of the capacity pot, and the short term signal given by this element of the payment. This issue was extensively debated during the development of the CPM payment weighting factors and will be commented on further in this paper.

Overall, the analysis presented in this paper was widely supported by respondents to the consultation.

SEM Committee's Response

The Regulatory Authorities will continue to regularly review and compile analysis for the SEM Committee with regard to market analysis, to ensure that process used for distribution the capacity pot among generations is in line with the objectives of the CPM.

6 WORK PACKAGE 2 - REVIEW OF CAPACITY REQUIREMENT

As detailed in information paper SEM-10-046, the following outputs were discussed from Work Package 2:

- Improving the transparency of the calculation process;
- Forced Outage Probability;
- Margin implied in the Capacity Requirement Calculation
- Treatment of Wind and the Wind Capacity Credit used.

6.1 TRANSPARENCY OF CAPACITY REQUIREMENT CALCULATION

Over the previous calculations of the Annual Capacity Payment Sum (ACPS), market participants requested additional transparency to be provided in relation to the calculation of the Capacity Requirement. The Regulatory Authorities have noted these comments and acted, they have published the inputs used for previous Capacity Requirement Calculations to further assist in the transparency of the calculation.

Summary of comments received:

Several respondents noted that it is appropriate that the SEM Committee should consult on the main input assumptions used to derive this estimate, especially the assumptions used in the estimation of demand growth, any changes to the demand profile, the forecast wind series and generator unit forced outage probabilities.

SEM Committee's Response:

The inputs to the Capacity Requirement Calculations are submitted to the Regulatory Authorities by SONI and Eirgrid for evaluation prior to input into the Adcal tool used to calculate the Capacity Requirement. These inputs will continue to be included and published in the Appendix of the Capacity Requirement section in the BNE Consultation / Decision papers going forward.

6.2 FORCED OUTAGE PROBABILITY

Seven respondents commented on the Forced Outage Probability (FOP) section of the historical paper.

Summary of comments received:

One respondent commented the rate is not reflective of FOP rates in the SEM and that in setting an artificially low FOP rate, the RA's reduce the capacity requirement below what is required in the SEM. Another respondent commented that the low FOP needs to consider the facilitation of increased penetration of wind, which leads to increased cycling of plant and in turn may increases the probability of forced outages.

A respondent commented that the current firm target rate is premised on the basis that it will incentivise improvements in plant availability, yet the Regulatory Authorities are also considering a reduction in the revenues of those investors charged with meeting those targets. They stated that effectively, the Regulatory Authorities are on one hand setting an aggressive standard to ensure load is met, yet on the other hand they are reducing the revenues earned by parties that must invest, operate and maintain plant to meet that standard and load. Another response also commented that an unrealistic Forced Outage Probability Rate for centrally dispatched generation will lead to more than 8 hour's loss of load in a given year.

Finally some respondents continue to disagree with the use of aspirational FOPs in the determination of the capacity requirements and believe the rolling average of actual all-island market FOPs should be used to determine the correct amount of capacity required to deliver the requisite security of supply.

SEM Committee's Response:

As stated in the historical paper, the 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[6]). It was recognised that this FOP was lower than the average FOP on an All Island basis, at that time the Regulatory Authorities believed that by establishing the Capacity Requirement against a target FOP value, generators will be provided with an incentive to improve their performance toward the target level.

It should be noted that the above rationale still applies and in general the Regulatory Authorities had seen an improvement in the outturn FOP values since the start of the SEM, but this has reduced in recent years as demonstrated in Figure 6.1:

[6] http://www.allislandproject.org/en/capacity-payments-decision.aspx?article=5f59436b-d753-498c-8ddd-013ad40aba00

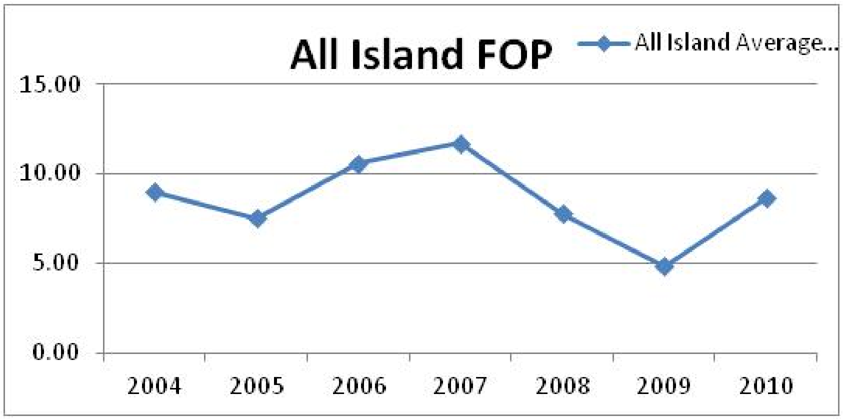

Figure 6.1- Regulatory Authorities Analysis - 5 year FOP Average.

Note that the 2011 FOP once calculated will be impacted due to outages in the Moyle and the Turlough Hill plants.

Eirgrid also calculate a FOP for the Republic of Ireland which includes 2011 year to date. This Generation System Forced Outage Rate is calculated on a 52-week rolling basis and is calculated as the sum of the weekly forced outage rates for the previous 52 weeks divided by 52.

The graph below is from the EirGrid website[7] and show the FOPs for the Republic of Ireland.

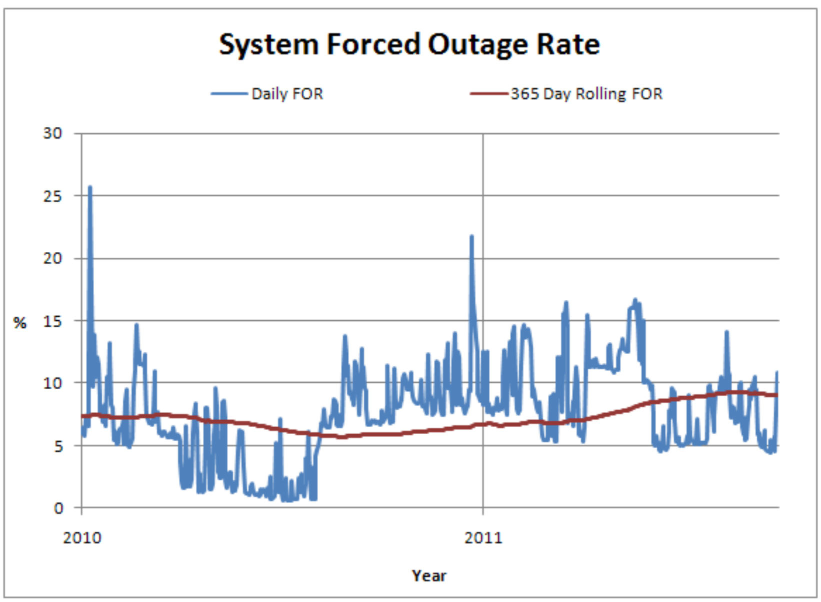

Figure 6.2- Eirgrid System Generation Forced Outage Rate for ROI plants only

[7] http://www.eirgrid.com/operations/systemperformancedata/generationsystemperformance/

One of the Objectives of the CPM is to provide an incentive for improvements in plant availability and for that plant to be available when required. Many respondents commented that the target level is too low and one respondent also stated that a figure of 6% is a reasonable expectation in the current circumstances.

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 SEM Committee will review the targeted FOP again for the 2016 Calculation.

However, the SEM Committee acknowledge the current FOP of 4.23% is ambitions and, following analysis of historical SEM forced outage probability information, the targeted FOP value used in the future capacity requirements calculation will be set at 5.91%.

This would have had the effect of increasing the 2012 capacity requirement by about 190MW from the previous FOP target of 4.23%.

6.3 MARGIN IMPLIED IN CAPACITY REQUIREMENT CALCULATION

Within the historical paper the Regulatory Authorities reiterated that the purpose of the Capacity Requirement Calculation is to determine the amount of capacity required to meet the Generation Adequacy setting of 8 hours loss of load per annum.

Summary of comments received:

A respondent stated that given developments in the market since March 2007 it may be prudent to reconsider the appropriateness of this value, particularly in light of comments made in Eirgrid's Generation Adequacy Report[8]. The Eirgrid report stated that "Even though there is sufficient capacity to comfortably exceed the standard of 8 hours loss of load expectation used, this does not guarantee that load shedding could not occur. It does however mean that the probability of load shedding is very low." The respondent also commented on likely further improvements to adequacy as a result of the completion of both the East-West and the second North-South interconnectors.

SEM Committee's Response:

The TSO produces an annual Generation Adequacy Report, which provides the TSO's considered view on one aspect of the power system, namely, generation adequacy, and the wider issues affecting it. Generation System Adequacy is determined as Loss of Load Expectation (LOLE) and is expressed as hours per year. The use of LOLE to assess Generation Adequacy is an internationally accepted practice. The accepted generation adequacy standard for Ireland is 8 hours loss of load expectation per year.

The SEM Committee remain of the view that it is necessary for the Annual Capacity Payment Sum to be determined on the basis of a single adequacy standard for the island of Ireland. This approach is consistent with the overall design of the SEM.

[8] Eirgrid, 2009; Eirgrid Generation Adequacy Report 2010-2016, p.59. Available at: http://www.eirgrid.com/media/Generation%20Adequacy%20Report%202010-2016.pdf

The SEM Committee is of the opinion that the accepted generation adequacy standard should continue to be 8 hours loss of load expectation per year.

6.4 IMPACT OF WIND ON THE CAPACITY REQUIREMENT CALCULATION

Another area the Regulatory Authorities investigated with the TSOs was the impact of wind on the Capacity Requirement Calculation. Currently the process includes the removal of the wind forecast from the demand forecast trace profile in order to determine the capacity requirement to be met by the conventional plant. The results from this modelling showed that in the case where the wind profile was modified to be high during certain peak hours, the change in the capacity requirement was not significant.

Summary of comments received:

Several respondents commented and agreed with the Regulatory Authorities assessment in the SEM-10-046 paper, that high wind penetration does not significantly change the capacity requirement in SEM[9].

A respondent had concerns about the treatment of wind and had raised this in each of its responses to the annual BNE consultations on the capacity requirement. They consider that the methodology whereby the wind profile is deducted from the demand and from generation is flawed, resulting in an understatement of the required margin.

Another respondent commented on the low contribution of wind to generation adequacy, especially at high penetration levels, and the fact that the contribution towards the capacity pot in terms of capacity requirement is much lower than the capacity eligible for payment, which is based on actual output.

SEM Committee's Response:

In 2009 the Regulatory Authorities conducted a modelling study to assess the effect of increasing wind penetration on the ability of the SEM to operate efficiently and effectively. The paper "Impact of High Levels of Wind Penetration in 2020 on the Single Electricity Market (SEM)[10]" suggests that the increasing penetration of wind generation in the market will have noticeable effects on the unconstrained market.

The SEM Committee have assessed the impact of the increasing wind levels on the capacity requirement methodology in the SEM-10-046 paper and concluded that it does not merit a change in the methodology at this time. It should be noted that as wind penetration increases on the system the capacity requirement methodology will need to be kept under review.

---

[9] The high wind scenario and high wind peak periods produced a calculation less that 4.4 % of the Capacity Requirement that was calculated for 2010.

[10] http://www.allislandproject.org/en/market_decision_documents.aspx?article=f8de4cfd-9a6b-4c04-8018-b89e74d0f6ba

7 WORK PACKAGE 3 - DEDUCTION OF IMR & AS & BNE PLANT OPTIONS

In SEM-10-046, Chapter 5 titled "Deduction of IMR and AS and BNE Plant Options" indicated the SEM Committee's views on Intra Marginal Rent (IMR) deduction within the Capacity Payment Mechanism:

*'…The implications of a change in estimated real IMR are thus significant and represent genuine volatility in the CPM calculations. The SEM Committee wishes to remove this level of volatility if possible. While one possibility would be to simply not deduct the IMR, it is the RA's view that **at equilibrium** the BNE **does** earn infra-marginal rent and this **should** be deducted from the Annualised Cost per kW of the BNE.*

7.1 THEORY OF THE CPM

Section 3 in the paper AIP/SEM/124/06[11] summarises the requirement for a CPM as follows:

'…in practice many electricity markets have found that a pure energy price alone is insufficient to ensure generation adequacy owing to issues surrounding price volatility (generally resulting in the energy market being unable to realise a true value of lost load (VOLL)), generation uncertainty and capital market imperfections. Consequently many electricity trading systems have adopted a mechanism which allows generators to recover at least a proportion of their costs via an alternative payment mechanism – a capacity payment mechanism (CPM)…'

The Regulatory Authorities have deducted the IMR from the BNE fixed costs, using the following justification (as detailed in AIP/SEM/07/14[12]).

'… The Regulatory Authorities have indicated that, in the assessment of the costs of a BNE peaking plant, an expectation of profits from the energy and ancillary service markets that such plant will reasonably expect to earn will be deducted from the fixed cost of a BNE peaking plant. The BNE peaking plant will expect to earn infra marginal rent from operation in the energy market. …

… If a CPM was based on the capital costs of a BNE peaking plant without taking into account infra marginal rent earned in the energy and ancillary service markets, over compensation would occur as the CPM would be based upon the fixed cost of a peaking plant that primarily provided only reserve and was wholly compensated for that provision only by the CPM. In reality compensation is very likely to also occur through activity in the energy market and the ancillary service market, if this is not taken into account; the CPM will over compensate all generators…. '

It should be noted that a key point in the selected design of the CPM within the broader theory of remunerating generators in the SEM is to consider the circumstance in which the market is **at equilibrium.**

Peaker units have low fixed costs and high variable costs. In general, in the SEM; a peaker recovers its variable costs through the energy market and fixed costs through capacity payments. However, at equilibrium the peaker is expected to earn excess IMR in the energy market during the hours of lost load. Hence, to avoid double payment, the deduction of this IMR from the BNE price was discussed in Work Package 3. It should be noted that ancillary service revenue is also deducted from the BNE cost for the purpose of calculating the required ACPS.

[11] http://www.allislandproject.org/GetAttachment.aspx?id=61cddfef-f617-404d-8c8d-1dc572614675

[12] http://www.allislandproject.org/GetAttachment.aspx?id=b131a78d-911c-4f42-9170-7803b5dcf661

Chapter 5 of the SEM-10-046 paper explored the issue of IMR deduction in the BNE calculation of the CPM in detail. Three potential options were considered in the paper and are summarised below. For analysis within the paper a notional bid price of €100/MWh was assumed for a distillate-fired plant.

Item	Value	Abbreviation
VOLL	10,295	VOLL
Price Cap	1,000	PCAP
Generation Security Standard (GSS) Hours	8	Outage Time
BID Price of Peaker (€/MWh)	100	BID
BNE Capacity	191	BNECAP

Table 7.1 – 2011 Inputs to the IMR calculation

The options offered were:

7.2 OPTION 1 - IMR DEDUCTED IN €/KW = [VOLL – BID PRICE OF BNE] / 1000 X 8 HOURS

IMR Deducted in €/kW = [VOLL-BID] / 1000 * Outage Time

Using the 2011 BNE calculation this equates to: [10,295-100]/1000*8 = €81.56/kW

If Option1 (VOLL) was used it would have resulted in an negative BNE price as shown in Table 7.2

Cost Item (€/kW/yr)	2011 Decision	2011 with VOLL IMR
Annualised BNE Cost (€/kW)	83.14	83.14
Ancillary Services (€/kW)	4.41	4.41
Infra-marginal Rent (€/kW)	0	81.56
Net Price (€/kW)	**78.73**	**-2.83**

Table 7.2 – ACPS 2011 Decision with Option 1

7.3 OPTION 2 - IMR DEDUCTED IN €/KW = [PCAP – BID PRICE OF BNE] /1000 X 8 HOURS

IMR Deducted in €/kW = [PCAP-BID] / 1000 * Outage Time

Using the 2011 BNE calculation this equates to: [1000-100]/1000*8 = €7.2/kW

If in addition, the FOP of the BNE is also considered in this calculation the IMR deduction will be less as the peaker may not be available to earn IMR during the of loss of load period. Note that the FOP in this calculation may be different to that used for the purposes of calculating the capacity requirement because in this instance it is the actual FOP of the BNE that this being estimated and not a targeted system FOP. In this instance the calculation is as follows (assuming an estimated Forced Outage Rate for the 2011 BNE Alstom GT13E2 of 2%):

Using the 2011 BNE calculation this equates to: [1000-100]/1000*8*(1- 2%) = €7.05/kW

Impact on the 2011 Calculation if Option 2 with the 2011 FOP was used is illustrated below:

Cost Item (€/kW/yr)	2011 Decision	2011 with PCAP IMR
Annualised BNE Cost (€/kW)	83.14	83.14
Ancillary Services (€/kW)	4.41	4.41
Infra-marginal Rent (€/kW)	0	7.05
Net Price (€/kW)	**78.73**	**71.68**

Table 7.3 – 2011 Decision with Option 2

The FOP used in this calculation going forward will be the FOP of the actual BNE plant not the target all island FOP.

7.4 OPTION 3 – DO NOTHING / STATUS QUO

This was a Status Quo option in which the Regulatory Authorities continue to use the current approach to measure the IMR of the BNE peaker. This approach has been used in previous years (2007 to 2011).

7.5 IMR RESPONSES

This section reviews the responses to the SEM-10-046 Chapter 5. 9 responses were received to the Discussion Paper from:

Name	Option 1	Option 2	Option 3	No preference	Do not deduct IMR
Bord Gáis				☑	
Bord Na Mona					☑
Endesa			☑		
ESB PG			☑		
IWEA				☑	
NIE Energy PPB					☑
Synergen		☑ Investigate Further			
The Consumer Council				☑	
Viridian					☑
Total	**0**	**1**	**2**	**3**	**3**

Table 7.5– IMR Responses received

Of the responses received, **zero** was in favour of option 1, **one was** in favour of option 2 (with further investigation) and **two** were in favour of option 3. **Three** had no preferences and **three** responses had stated no direct preference to the options but indicated their preference to not deducting the IMR from the BNE process.

Summary of comments received:

One respondent suggested that option 1 be rejected, and that option 2 be investigated in more detail to confirm that it is equivalent to option 3 over an investment time horizon. Another respondent commented that the "equilibrium state", which the Regulatory Authorities are using to model the market, does not reflect the market realities faced by investors. Reducing the pot under the auspices of providing certainty will actually increase risks for investors and also potentially jeopardises the security of the system. Another respondent believed that the Regulatory Authorities should re-consider their view on abandoning the principle of deducting the IMR altogether, as they agree that the status quo arrangement adds significant volatility to the CPM, and therefore acts as a significant impediment to investor confidence in the market.

Several respondents were more supportive of maintaining the Status Quo option, which involves using Plexos runs to evaluate IMR. They consider it significant that only once was IMR greater than zero in the BNE Fixed Cost calculation.

Another suggested that they support the status quo approach until the assumed volatility is confirmed. However in the event that further modelling demonstrates that the CPM becomes as volatile in reality as in theory, then in terms of the two options presented, they support option 2 which uses PCAP in the determination of the infra-marginal rent. This formula should be improved by the inclusion of the FOP in this formula as suggested by the Regulatory Authorities.

SEM Committee's Response:

The primary objective of an electricity market is to ensure security of supply at the lowest sustainable cost. Whereas the CPM addresses some of the shortcomings of an energy only market, a key priority for the BNE investor within this market is the level of risk associated to the remuneration of his investment. A volatile IMR depending on the many circumstances that happen in system operation will result in the generators receiving an unstable and unpredictable income every year. This goes against the objectives of the CPM of volatility and price stability.

As was stated previously, a key point in the design of the CPM within the broader theory of remunerating generators in the SEM is to consider the circumstance in which the market is at equilibrium. At equilibrium, the peaker will set the marginal price (whenever it is scheduled) as it has the highest variable costs. Also within this system:

- There must be some hours with non-served energy and a marginal price equal to VOLL, since otherwise the system cannot be in equilibrium;
- Not all peakers will be equal or will have bought the fuel at the same price, therefore there will be some differences in their bids and some of them will be slightly infra-marginal;
- The peaker will earn Ancillary Services.
- It is assumed that, as a profit maximising entity, the BNE peaking plant will operate in all those trading periods that provide it with infra marginal rent, (also referred to as a positive spark spread).

It should be noted that the above theory is based on a market at equilibrium and this is the basis that the CPM is calculated in the SEM. In AIP/SEM/111/06[13] the Regulatory Authorities stated that a single Generation Security Standard 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 Regulatory Authorities subsequently decided on a Generation Security Standard of 8 hours Loss of Load Expectation per annum.

[13] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?article=64eb1095-92de-4ae2-a053-19a3cfc2307b

Using the Generation Security Standard of 8 hours loss of load the system and considering the Trading and Settlement Code Market Price Cap (PCAP), 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.

Having considered the responses received to the discussion paper, **the SEM Committee has decided to pursue its preferred option (Option 2, which will account for the FOP of the BNE in its calculation)**.

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

This method will reduce the volatility and / or potential uncertainty and risk currently in place regarding the IMR deduction. The key variables in the method are semi-fixed (VOLL, PCAP, Generation Security Standard) 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). However the impact of even significant movements in fuel price (such as doubling or halving) on the calculation is relatively small.

The CPM must achieve its objectives at the lowest reasonable cost, i.e. most efficiently. It should not "double pay" generators but must achieve efficient price signals for long term investments. If IMR was not deducted from the BNE calculation, then there is the potential of certain generators to be over rewarded. The inclusion of option 2 should 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. It is the SEM Committees intention to include Option 2 in the 2013 BNE Calculation consultation process.

8 WORK PACKAGE 4 - BNE PEAKER PLANT FUEL OPTIONS

Work package 4 looked at alternative technology types for the BNE calculation and the fuel choice for the peaking plant.

Summary of comments received:

Several respondents commented on this section, welcoming the discussion and considered the conclusions contained to be reasonable. They also welcomed the Regulatory Authorities intention to continue with the current methodology as it goes some way to reducing the year on year volatility.

One respondent agreed with the view of the Regulatory Authorities that the market for secondary trading of gas transmission capacity is insufficiently developed, and that an operator of a gas fired peaking plant would therefore have to buy annual capacity. While another respondent stated that the issue of gas capacity will need to be carefully considered as the market proposals develop. Another respondent commented that the CPM does not value the flexible characteristics of pumped storage, and stated that the CPM is not designed to deliver operational flexibility - merely to have MW available at given points in time and ancillary service type products should be explicitly separated from any issues associated with the CPM.

SEM Committee's Response:

The level of analysis that has been undertaken over the last number of years to evaluate the technology choices for the BNE plant has been quite exhaustive and the SEM Committee agree with some of the comments received, such as, it is unlikely that significant changes in the technology options will arise on a year to year basis. The alternative technology types are likely to evolve over the medium term as new technology is developed and has demonstrated significant operational hours to prove its reliability.

In relation to gas transmission capacity, the Regulatory Authorities will continue to assess trading of gas transmission capacity and its impact to the BNE peaker (including development of the Common Arrangements for Gas). These developments will be considered in the BNE consultation when it is appropriate to do so.

9 WORK PACKAGE 5 - EXCHANGE RATE FOR CPM

Work Package 5 looked at setting the exchange rate at a monthly level to reduce the impact of fluctuations in the exchange rate.

Summary of comments received:

One respondent commented that a monthly exchange rate should not present a significant challenge to the market operations, as the capacity payments and charges are paid and collected on the basis of stand-alone monthly pots. Several respondents further commented on the separation in time between the determination of the exchange rate used in the calculation of the BNE cost and that used as the Annual Capacity Exchange Rate (ACERy) published by SEMO for payment in the relevant settlement year. They stated that it might be more sensible to use the same exchange rate for both.

Several respondents also called for a non-discriminatory approach to the CPM and as such, segmenting capacity pots in the SEM is not appropriate. They agreed that the CPM should remain as a single market pool of money, and not be separated into two jurisdictional pots, for if the ACPS was split into two separate sterling and euro jurisdictional pots, it would be difficult to match the payments in each currency with the respective charges in the same currency.

SEM Committee's Response:

The issue of exchange rate risk represents a potential gain or loss due to currency fluctuations from suppliers to generators, (and or vice versa). As stated in the historical paper, the SEM is truly cross-jurisdictional, developed by the two Regulators, supported and guided by the two Ministers and their Departments and facilitated by the two System Operators and the Single Electricity Market Operator. In this context the SEM Committee do not believe market segmentation is appropriate, which would result in separate RoI and NI capacity pots (and therefore jurisdictional pots). It is the SEM Committee view that the exchange rate should be fixed annually and use forward exchange rates.

As for the separation in time between the determination of the exchange rate used in the calculation of the BNE cost and the Capacity Pot, it is the SEM Committee's view that the two should remain separated as there is a significant period of time between the BNE calculation and the Annual Capacity Exchange Rate (ACER). The decision on the BNE calculation is made in the month of June whereas the ACER is determined by the average of the spot rate with the forward point adjustment for the last five business days of November. In 2011 the SEM Committee stated that the Regulatory Authorities agreed with participants comments concerning the large volatility in the EUR/GBP in recent years. The Regulatory Authorities also recognised that a balance must be struck between setting the price as close to the period as possible and the certainty of the rate. Based upon these considerations, the SEM Committee revised their original method for calculating the Annual Capacity Exchange Rate in 2011 and decided that the value of the ACER should be determined based on the period up to the end of November 2010.[14]

The annual fixing of the exchange rate provides greater certainty to generators and eliminates competitive and jurisdictional distortions; hence the setting of the exchange rate on an annual basis offers a long term view consistent with the principles of capacity pot predictability and ease of calculation within the market operator.

[14] http://www.allislandproject.org/en/TS_Decision_Documents.aspx?article=356d0517-01b2-4ac0-b677-7749962cfe99

10 WORK PACKAGE 6 -TREATMENT OF GENERATOR TYPES IN CPM (WIND ETC)

The discussion paper SEM/11/019[15] (CPM Medium Term Review Work Package 6 onwards - Discussion Paper) was published in April 2011 seeking views from interested parties. This paper covered the remaining work packages (6, 8, 9 and 10).The following areas where investigated;

- Treatment of Generator types in the CPM,
- Incentives for Generators,
- Timing and distribution of Capacity Payments,
- Impact of the CPM on Customers.

22 responses were received in relation to the Work Package 6 paper from AES, ART, Bord Gáis Energy, Bord na Móna PowerGen, EirGrid, Endesa Ireland, Enercomm, Energy Generation Infrastructure [EGI], ESB, ESB Wind Development (ESBWD), Irish Wind Energy Association (IWEA), National Electricity Association of Ireland Ltd (NEAI), PHES LTD, Power Procurement Business (PPB), SSE Renewables, Synergen, The Consumer Council, Tynagh Energy Ltd, Viridian Power and Energy (VPE) and the Wärtsilä Corporation. Two responses were also received as Private and Confidential.

As part of its investigation into the CPM Medium Term Review the Regulatory Authorities procured consultancy support from Poyry[16] for some aspects of the work required. Poyry produced a detailed report, which was attached in Appendix 1 of the SEM/11/019 paper. This provided a number of alternative options and possible improvements for the Regulatory Authorities to consider, including pros and cons of the different solutions and how the recommendations meet the objectives of the CPM. The report details the performance of the current CPM design, the performance of the CPM in future years and offers options for reform.

Work package 6 looked at the Treatment of Generator types in the CPM, with in this work package views were invited on,

- The Capacity Credit Scenario
- Capacity Credit of Wind Generation
- CPM Impact on Interconnectors
- Energy Limited Units

10.1 THE CAPACITY CREDIT SCENARIO

The Capacity Credit scenario looked at introducing generator/technology adjusted payments or ‘capacity credits’ which weight fixed payments towards generators that are likely to be available in times of tight system margin. In this reform option, each plant or plant type is allocated a ‘capacity credit factor’ through which ex-ante payments are adjusted to take account of the ‘firm capacity’ provision of generators with the intention to reward generator contribution at peak demand with a higher capacity credit. The SEM/11/019 paper invited views on whether the Regulatory Authorities should look more closely at a Capacity Credit scenario for the payment of different

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

[1616] http://www.allislandproject.org/GetAttachment.aspx?id=7440e0f4-a8d1-47b0-baba-87551201d0d0 generation types and whether a Capacity credit methodology was appropriate for the CPM. 15 respondents commented on the Capacity Credit scenario.

Summary of comments received:

Several respondents were against this scenario and stated that it would require a significant change to the CPM. They stated that it would introduce further uncertainty in the predictability of revenues for generators. A respondent stated that in principle it is a useful approach provided it is implemented in a manner that does not involve a high level of complexity and bureaucracy. Other respondents believed that the capacity credit suggestion may have some merit, however some stated that it fails to take account of the long-term contribution to security of supply provided by wind generation, it adds a significant layer of complexity and is likely to increase regulatory risk. Another respondent commented that, it is acknowledged that the method of allocating the capacity credits could be problematic, creating significant disruption in the industry unless it is robust and transparent and not subject to frequent change.

Some respondents were of the view that Capacity Credits for generator types is an appropriate and economically rational method of allocating the correct value to generators for their contribution to system adequacy and that the Regulatory Authorities should consider capacity credits that reflect the contribution of each generation type to security of supply.

One respondent did not favour capacity credits on a technology basis applied to ex-ante payments; however they did feel that consideration should be given to allocating CPM "Credits" on a gen-set basis. Another stated that it would not be appropriate to determine a standard capacity credit based on plant type, rather credit should be calculated for each individual unit, ensuring a proper reward for availability.

Another respondent commented that the application of capacity credits in the CPM would be very complex and expensive to implement without providing clear benefits. There is no compelling need to change the existing approach and they would suggest it would be imprudent to do so.

SEM Committee's Response:

While the concept does have its merits, the capacity credit scenario would require a significant change to the CPM methodology and it would introduce a significant layer of complexity, uncertainty and subjectivity associated with the determination of capacity credit factors across the different technology types. Hence, the SEM Committee does not believe that a capacity credit methodology is appropriate for the CPM at this stage.

10.2 CAPACITY CREDIT OF WIND GENERATION

Wind generation gets paid a capacity payment based on its Eligible Availability in each half-hour. Within the discussion paper the Regulatory Authorities asked for views on whether, the current mechanism fairly rewards wind generation and whether this should be revised. The Regulatory Authorities welcomed alternative suggestions for allocating capacity payments between generator types. In total 13 respondents commented on this section and a summary of their comments are highlighted below.

Summary of comments received:

Several respondents commented that there should not be a separate stream of capacity payments for wind. Some stated that the current mechanism over-rewards wind and that reward should be based on the technology's contribution to system security and reliability.

Another respondent commented that stemming from the SEM Committee's previous analysis on 'the Treatment of Different Technology Types', it is suggested that wind generation has been and is being over-compensated in the SEM and that a movement to a larger proportion of ex-post payments would provide a better balance. Another respondent commended that if the proposed change were implemented, Ireland would need to make changes to the support mechanism for wind and that these changes should be coordinated, so that there is not a further delay in wind investments.

One respondent argued that the ex-ante element already accounts for wind's inability to always meet a declared output precisely. They thought there was no reason to revise this in the coming years with an imminent European market integration process in mind. Another respondent stated that the Capacity payments should be made to parties on the basis of their contribution towards key objectives, i.e. contribution towards system adequacy (in the longer term) and availability (in the shorter term). There is no prima facia rationale to pay some parties more than others for the same service. Differentiation in payments should only be determined on the basis of availability and remuneration for other services (e.g. flexibility) should be remunerated separately. Other respondents agreed with this position.

SEM Committee's Response:

The Trading & Settlement Code treats all generation equally and consequentially cannot deliver preferential payment for one MW of availability over another without alteration. A change to the CPM, for example, having a different separate capacity pot for wind generation, would require significant modifications and may add additional complexity to the CPM. As highlighted in the discussion paper, the CPM does recognise the value of wind in the calculation of the total pot and under the ex-post payment stream.

For these reasons the SEM Committee rejects the concept of a separate stream of capacity payments just for wind and no change in the allocation of capacity payments between generator types is being proposed at this point in time.

10.3 CPM IMPACT ON INTERCONNECTORS

The Regulatory Authorities welcomed alternative suggestions for allocating capacity payments between interconnectors and interconnector users and whether these payments and charges would be treated differently than under the current methodology in the CPM. 8 responses were received in relation to the CPM impact on interconnectors.

Summary of comments received:

One respondent stated that due to uncertainty surrounding compliance with EU initiatives and UK Electricity Market Reform they do not believe that unnecessary change should be introduced at this point. Further change should only be considered when the impact of EU compliance and potential changes to the UK electricity market are known. Therefore until the Great Britain electricity market rules are developed, it would be inadvisable to change the CPM arrangements in relation to interconnectors. Several other respondents replied along similar lines, highlighting that any changes should be made in the context of the overall work arising from the emerging target model for a European Energy Market.

Another respondent believed the existing regime is an appropriate (albeit imperfect) means of attempting to ensure coupling of SEM and BETTA markets without creating additional seams issues between the two markets.

SEM Committee's Response:

The SEM Committee is mindful that Regional Integration initiatives will have a significant impact on interconnectors in the future. The Regional Integration project is at an early stage and the SEM Committee has decided not to make any substantive changes to the current methodology for capacity payments received by interconnectors / interconnector users at this point in time. Any changes will be considered as part of the wider Regional Integration work stream. The SEM Committee will also continue to assess developments in the GB market and their impact on interconnectors / interconnector users.

10.4 ENERGY LIMITED UNITS

The SEM/11/019 discussion paper asked if energy limited and pumped hydro storage units be treated differently to the current methodology in the CPM. 6 responses were received in relation to energy limited and pumped hydro storage units.

Summary of comments received:

Several respondents felt that they did not see any compelling reasons why the current methodology for the treatment of pumped storage and energy limited plant should be changed. One respondent commented that it is likely that substantial and significant changes to the SEM design will need to be considered in the near future to ensure compliance with the European Target Model and given this it seems pointless to make tweaks to the current design which will result in an even greater level of regulatory uncertainty and risk for market participants.

Another respondent commented that Energy limited generator units and pumped storage units effectively have their spare capacity up to their energy limit allocated optimally into periods of the highest capacity value. This is in line with the spirit of dispatch indifferent market revenues within the context of central dispatch. Given that the principle of its operation is consistent with the SEM design, they see little point in unpicking this element of the SEM T&S Code CPM design.

A respondent also commented that under the current market rules, Hydro-electric plant and Pumped Storage are treated in a manner which both allows the TSO optimum control for dispatch and at the same time rewards the plants themselves for the predictable energy they provide. The issue is that while these plants are energy limited, they are always predictable and controllable and thus have a greater contribution to system capacity than other variable plants and this is not rewarded under in the current capacity market. However, rather than change the existing T&S Code rules, the respondent believes this can be addressed in a more global manner with a change in weighting to 50:50 ex-ante/ex post and/or adoption of capacity credits.

Other respondents felt that the current methodology should be changed to encourage new pumped storage into the market.

SEM Committee's Response:

The SEM Committee agrees that this type of generation adds significant value to the system. However, with uncertainly around Regional Integration the SEM Committee has decided not to make any substantive changes to the methodology in respect of this type of plant for the time being. To do so would likely involve significant system changes and associated costs. Given the current European Integration landscape, the Regulatory Authorities are working on a framework to develop and implement solutions to ensure compliance to the potential demands of the EU integration. The SEM Committee feels at this point in time the current methodology in relation to energy limited and pumped hydro storage units in the CPM should remain unchanged.

11 WORK PACKAGE 7 - BNE CALCULATION METHODOLOGY

The Discussion Paper SEM-10-068[17] (Work Package 7 - BNE Calculation Methodology Discussion Paper) was published in October 2010 seeking views from interested parties. This paper covered the review the BNE Calculation Methodology used with in the CPM. This paper investigated the following areas;

- CPM Design in other Regions and International experiences in delivering adequate capacity
- BNE Calculation Methodology 2006
- Summary of the Options in the BNE Calculation Methodology Review 2009 - option 2, 5 and 6
- Indexing Methods
- Impact of Options on WACC Calculations
- Options for Price floors

16 responses were received in relation to the Work Package 7 paper from AES, BG, Bord na Móna, Endesa, ESB I, ESB PG, ESB WD, Forfás - Enterprise Ireland - IDA Ireland, IBEC, IWEA, PPB, PPIG, RES, SYNERGEN, The Consumer Council and Viridian Power and Energy (VPE).

11.1 WORK PACKAGE 7 - CPM DESIGN IN OTHER REGIONS AND INTERNATIONAL EXPERIENCES IN DELIVERING ADEQUATE CAPACITY

This section of the paper investigated international energy only markets, price-based capacity mechanisms and quantity-based capacity mechanisms. A detailed analysis of international experiences was conducted and 5 quantity-based capacity payment systems in New England, PJM, New York, Western Australia and Greece were reviewed. The key differences between these systems include the bearer of responsibility for securing obligations (whether Load Serving Entities or the ISO); use of auction processes or regulatory processes to set the price for capacity; frequency of review and review horizon for prices and volumes; and the differences in price formation and the role of BNE in price calculation. Six price-based capacity payment systems in Ireland, Spain, Argentina, Italy, South Korea and Chile were also reviewed. The key differences established include capacity payment timeframes; frequency of regulatory review and review horizon and the operation of separate investment and availability incentives price as in Spain.

[17] http://www.allislandproject.org/GetAttachment.aspx?id=88db796c-461a-4ca5-abe1-fb46ba7ed31b

Summary of comments received:

11 respondents commented on this section of the paper. The majority welcomed the analysis of international experience in delivering adequate capacity. The respondents stated that the international comparison in the discussion paper provided a useful insight on how the SEM model compares internationally and to other methods of pricing capacity. However, several respondents commented that the international experiences have to be viewed in the context of the situation of each market - and the relationship of any capacity payment scheme to other elements of the market design.

Several respondents commented on the price-based capacity mechanism, one respondent stated that since the SEM Committee has consistently stated that it considers the CPM as a key feature of the SEM design, in their view of this it seems prudent to accept that the CPM as a price-based capacity mechanism which should remain in place for the foreseeable future and the CPM Review should address issues such as CPM price stability, market entry and exit signals, and incentivising the right portfolio mix for facilitation of renewables, while recognising investor risk and ability to bank role new projects if they are to materialise. Another respondent noted that price-based capacity mechanisms are better at delivering capacity but at a higher market price. SEM currently operates under a price based mechanism and the Regulator Authorities should be minded to consider alternative mechanisms only if they will provide benefits to consumers through lower prices.

Some respondents did mention the merit in an auction mechanism being used to set the capacity price, however they would not favour any change in the market rules which would lead to increased and different regulation for them over and above any other generator. Another respondent highlighted that the long-term strategy should include plans to move towards a competitive ancillary services market. Auctions for the provision of ancillary services should be developed, allowing new entrants to offer for long-term ancillary service contracts and existing market participants to offer for annual contracts.

Regarding differentiation some respondents commented that the introduction of differentiation would be in direct conflict with the current CPM objective of fairness as currently the rules of the CPM ensure that all generators are treated the same and receive the same payments when available at the same time.

SEM Committee's Response:

As previously stated the SEM Committee considers the CPM as a key feature of the SEM design and that the concept of the CPM should remain in place and do not propose a change from the current capacity payment system at this point in time. Under the current design of the CPM, the Regulatory Authorities are responsible for setting a new ACPS every year. The experiences of other markets suggest considering a review period which sets the ACPS for several years ahead rather than for the following year. This will be reviewed in the oncoming sections of this paper.

11.2 BNE CALCULATION METHODOLOGY 2006 – OPTION 1 REVISITED

This section of the Discussion Paper SEM-10-068 invited views on the possible approaches for determining the fixed costs of a BNE peaking plant for the purposes of setting the Annual Capacity Payment Sum. It revisited the option for calculating the BNE element by assessing the market equilibrium price of a peaking plant (marginal cost of incremental capacity) in the SEM based on an assessment of Value of Lost Load (VOLL), Loss of Load Probability (LOLP) and the peaking plants forced outage probability. Option 1 uses the following formula:

Option 1 = (1 – FOP) * LOLP * VOLL

All of the input parameters are considered on an annual basis, and over the past number of years most have been relatively constant.

Summary of comments received:

12 respondents commented on this section of the paper.

Some respondents considered it prudent to have revisited this option given the subsequent determination of the input parameters. Several respondents also felt that there is some merit in considering this option as an alternative to the current BNE process as it. It is a lot simpler, more predictable, and removes a lot of the administrative burden in the determination of the BNE figure. Concerns were also highlight regarding the current level of VOLL and how it is calculated.

Several respondents were against any move away from the current methodology. They stated their belief that the current methodology serves its purposes, and is not fundamentally flawed. They argued that any possible change in BNE Calculation methodology would create regulatory uncertainty and reduce the forecastability of capacity payments, which will give rise to consequential increases in the costs of capital and the financeability of projects.

SEM Committee's Response:

Following consultation of SEM-124-06, Option 1 was discarded due to concerns relating to the difficulty surrounding the determination of VOLL for the SEM. However, while overall there may be benefits of this method, the SEM Committee are against any significant move away from the current methodology at this time. This is particularly with a view to the ongoing work on Regional Integration. As stated in the Executive Summary the SEM Committee will make minor changes to certain aspects of the CPM calculation.

11.3 SUMMARY OF THE OPTIONS IN THE BNE CALCULATION METHODOLOGY REVIEW 2009

The Regulatory Authorities had considered in 2008 the options available that may be used to reduce the perceived volatility in the Best New Entrant Fixed Cost (BNEFC) calculation. These are summarised below;

- Option 1 – Calculate BNEFC on an annual basis with all components recalculated annually.
- Option 2 - Calculate BNEFC on an annual basis but some components cost remain constant for a number of years
- Option 3 - Calculate BNEFC on an annual basis with all components recalculated annually. Smoothing is then applied.
- Option 4 - Calculate BNEFC on an annual basis but some components cost remain constant for a number of years. Smoothing is then applied.
- Option 5 – Calculate the BNEFC and keep it in place for a multiple year period.
- Option 6 – Fixed price for new entrants

Within the discussion paper the Regulatory Authorities decided that Option 2, Option 5 and Option 6 be reviewed within the medium term review.

Summary of comments received:

Overall most respondents to the consultation favoured that these matters be considered within the medium term review and some respondents had questioned if there really was an issue with the BNE fixed cost and suggested that very limited changes to the methodology was required.

15 respondents commented on these options, one respondent was against all options whereas the remainder commented on which option they felt would best suit any future changes to the CPM calculation. Ten respondents commented on Option 2, two commented in favour of the Option 5 and Option 6.

It should be noted that several respondents stated that they believe that the current methodology serves its purposes, and is not fundamentally flawed. In addition, some respondents observed that the BNE estimation process has stabilised, with no significant changes to the approach adopted in the process to estimate the 2011 pot, compared to that used to estimate the 2010 pot. It is this consistency of the current approach that will give the strongest reassurance to market participants and potential investors alike, on the stability of the capacity market into the future.

11.3.1 OPTION 2 – CALCULATE BNEFC ON AN ANNUAL BASIS BUT RETAIN THE COST OF SOME COMPONENTS CONSTANT FOR A NUMBER OF YEARS

Ten respondents commented on Option 2 with the majority in favour of using this option, two responses were against this option.

Summary of comments received:

Most of the respondents stated that there was merit in fixing some of the components for a number of years, as at a high-level it would seem to provide the transparency and stability desired by investors as well as the incentives and market reflectivity desired by the Regulatory Authorities. This is however dependent on what parameters are fixed and for how long. The commented that indexation of the fixed items would also be appropriate. It is proposed that the items could be adjusted as necessary e.g. technology of peaker, choice of fuel, environmental standards to be met. They believed it is important to fix these items used to ensure consistency between years.

One respondent commented that it would bring a greater level of stability and certainty to the annual capacity pot calculation while allowing for the adjustment for other more appropriate line items as needed. It would be important that the items fixed are those which would not be expected to move to any significant degree over the time horizon. Indexation of the fixed items would also be appropriate. For those items that remain unfixed and change annually, reference sources for each item should be consulted and agreed upon.

Another respondent also commented that essentially Option 2 is a sub-set of option 5, as option two considers fixing certain aspects of the BNE price structure over a multi-year period, (subject to indexation) whereas option 5 proposes indexing the full BNE price over a multi-year period. In both cases, the duration of the review period suggested was of the order of three to five years

Respondents also highlighted that there is an element of risk of a stepped change at the end of each review period. Several respondents considered a five-year rolling average of the BNEFC to be a more appropriate methodology of introducing both stability and predictability.

Two respondents were against Option 2, one argued that it does not necessarily follow that fixing elements of the BNE cost calculation would add stability to the pot size, as doing so ignores that the BNE cost is but one element of the ACPS calculation. Another argued that Option 2 will under / over recover over each fixed period, even with indexing method applied to some cost elements and others being reviewed annually. They also commented that the trade-off being sought by the proponents of Option 2 is that the benefits of stability outweigh those of a more frequent assessment of costs.

11.3.2 OPTION 5 - CALCULATE THE BNEFC AND RETAIN FOR 3 OR 5 YEARS SUBJECT TO INDEXING

Two respondents commented that option 5 would fix BNEFC significantly reducing volatility. Once the BNE plant technology and associated costs are calculated, they should be fixed for 3-5 years. The only change during the period should be in the determination of the annual capacity requirement and the indexation of costs.

Another respondent agreed that option 5, which would fix the capacity pot for a number of years, will most likely create a stepped change in capacity payments at the end of each period it is set for and it would also introduce the risk of providing a cyclic investment signal, where there would either be a flood of investments over the set period or a scarcity, depending on how the market costs move against the capacity pot. Several other respondents were not in favour of this option and believe that it will lead to step changes in the CPM mechanism.

11.3.3 INDEXING

In relation to the above options the discussion paper also asked for views on which would be the most appropriate method of indexing (if adopted). Several respondents commented that should indexation be necessary in any of the options selected, then the most appropriate indexation to use must be the one that most closely matches the costs of building new power generators.

On the issue of indexing, one respondent commented that a published and widely accepted measure of inflation should be used. Proprietary or commercial indices should be avoided as should narrowly defined measures that are more likely to be at risk of wide variations that are unrelated and inconsistent with the actual costs one is seeking to index. A measure such as the HICP would largely be consistent with their preliminary views on this issue.

Another respondent suggested looking at the range of indices available such as EPCCI for the investment costs of a peaking unit (i.e. EPC costs etc.) and the relevant HICP for localised costs (such as maintenance and operations costs). Another respondent considered that the consumer price index (CPI), the index that has been used in the BNE calculations since market start, is the appropriate index to use when adjusting costs associated with investment in a BNE in the SEM.

Another respondent stated that generic inflation indicators are not capable of reflecting the cost trends of power plants. Hence a specific index that is more closely associated with underlying cost trends would be favourable. However, from experience, they also agree that relying on an index produced by a commercial enterprise is not an ideal inflator since such indices can be skewed, creating suspicion and reason to question the integrity of the data. Another respondent commented that indexation could increase volatility within the BNE calculation and the selection of specific indexation is problematic and so indexation should be rejected.

11.3.4 OPTION 6 – FIXED PRICE FOR NEW ENTRANTS

Several respondents commented in support of Option 6. Most were against it.

One respondent strongly supports the proposal for a separate capacity payment for new entrants. It is their view that capacity auctions for new investment should guarantee an annual capacity payment over 10-15 years, sufficient to enable investors to recover their capital costs. Another respondent commented that Option 6 should be adopted as this option gives the future revenue certainty that allows investors to obtain financing at the costs envisaged in the WACC calculations. This would enhances project bankability and facilitate investment with financial institutions in a very difficult economic climate and it is already operating successfully in Spain.

Another respondent commented that the viability of this option would depend on the duration for which capacity revenues are fixed for a new plant, how protection against overbuild in the market can be implemented, and the impact on capacity revenues for incumbent generators. In relation to the alternatives suggested for the implementation of this option, they also felt that the option should only be considered for conventional plant, i.e. plant operating on a merchant basis that depend on capacity revenues as a key element in covering their running and capital costs.

Several respondents highlighted their concerns to the specific proposal under option 6, which sees wind farms excluded from a market mechanism purely on the basis they receive external support, rather than on any technical or commercial rationale. They believe this proposal to be a worrying precedent and would strongly oppose such a concept. Another respondent also stated that the Spanish model is also problematic as it requires a determination of what represents a “significant investment” for existing generators to qualify and hence would represent a significant regulatory burden.

Another respondent commented that this option should not be taken forward as they believe it is discriminatory in nature and is inappropriate given the reward streams available to generators in the SEM. They also believe that option 6 would require the removal of the BCoP.

11.3.5 IMPACT OF OPTIONS ON WACC CALCULATIONS

In the BNE calculations, the calculation of WACC is a key area that historically has resulted in a lot of comments from Market Participants. The Regulatory Authorities in this section looked at the methodology used in calculating the various WACC parameters to ensure the approach is fully transparent and that all assumptions used are clear and understood.

Summary of comments received:

Several of the respondents argued that all parameters of the WACC calculation should be reviewed on an annual basis in order to reflect actual market conditions. Respondents also argued the Regulatory Authorities have set the WACC too low and that the volatility of these parameters is a cause of uncertainty for market participants. Some respondents noted that this uncertainty would be significantly reduced if the SEM Committee agreed fixed sources for these parameters that are utilized to calculate the BNE FC. Several respondents suggest that the Regulatory Authorities consult on appropriate public sources for the WACC inputs, so that market participants can follow the movements of these inputs and will prepared for any changes to the WACC.

One respondent commented that there has been significant volatility in the WACC used in the calculation of the BNE price and it is not apparent that the rates used reflect the actual cost of capital that would be incurred by an investor. In normal price controls, the WACC is generally set for the duration of the period and hence it would not be unreasonable to either fix the WACC for a three year period or alternatively to adopt a rolling average WACC to smooth out fluctuations.

Another respondent commented that the use of WACC has significant international precedent and they can see no reason to move away from this approach. However, given the scope for regulatory control, they believe that the WACC should be placed outside the RA's control and the Regulatory Authorities should procure an independent forecast by respected experts. Whereas another respondent stated that the regulators and their consultants need to ensure that the implications for Ireland’s relative cost competitiveness are fully considered when determining the WACC value.

SEM Committee’s Response:

The Regulatory Authorities welcome the comments and note that they reflect the concerns that have been raised in previous consultations on the BNE Peaker costs. The Regulatory Authorities have and will continue to endeavour to make the future BNE Calculations as transparent as possible and published extensive data and assumptions on the WACC parameters as determined by external consultants.

The Regulatory Authorities believe that there is merit in Option 5: Calculate the BNEFC and fixing the components for a number of years, as at a high-level, this will provide transparency and stability. The Regulatory Authorities propose to fix the elements of the BNE calculation for **“3 Years”**. In principle, the fewer the variables that have to be re-estimated each year, the more stable the BNE cost will be, at least over the 3 year period. The only change during the period should be in the determination of the annual capacity requirement and the indexation of costs (using the Irish Harmonised Index of Consumer Prices (HICP) and the UK HICP). 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 do so.

This option will provide a greater degree of revenue certainty to generators, and a more stable year to year pattern of capacity payments. The SEM Committee acknowledge that the implementation of this option may result in changes to the capacity pot from one period to the next but they feel that a 3 year indexed BNE will provide long term security with the price being set in the current transparent method. This three year period is also set with 2016 European Integration timelines in mind and the 2016 calculation process will be re-evaluated in line with any proposed changes to the SEM.

This option will provide a greater degree of revenue certainty to generators, and a more stable year to year pattern of capacity payments and it is the Regulatory Authorities opinion that this option would also help provide some additional stability for generators, as the BNE Costs would be tied down for a number of years, which in turn should therefore improve cash flow projections for future generators.

The 2013 BNE calculation will be completed using the current methodology and for the following two years, 2014 and 2015, a level of indexing applied to the BNE Peaker Cost (€/kW/yr). For 2014 and 2015 the fixed element price for the BNE Peaker Cost (€/kW/yr) will be subject to an indexing method. As highlighted in the discussion paper, in previous exercises such as for quantification of VOLL in the SEM, the Regulatory Authorities have employed the Irish Harmonised Index of Consumer Prices (HICP) and the UK HICP. Its value in subsequent calendar years would be determined by taking its values in the preceding year and up-rating it by applying the weighted average of the year-on-year increase in the Irish HICP (using a weight of two-thirds) and the UK HICP (using a weighting of one-third) in the month of March of the preceding year by comparison with that a year earlier. This will be re-evaluated for the decision paper. The sources for the data on HICPs will be obtained from the Central Statistics Office (CSO) in Ireland and the Office for National Statistics in the UK.

12 WORK PACKAGE 8 - INCENTIVES FOR GENERATORS

This section of the discussion paper looked at Ancillary Services and the CPM with the flexibility payment scenario, Capacity Penalties and the scenario of incentives for new entrants outlined in the Poyry report.

12.1 ANCILLARY SERVICES (AS) AND THE CPM

Within the discussion paper the Regulatory Authorities had stated that the CPM and the AS revenue payment streams have two separate objectives and that these should remain separate. 17 respondents offered comments on whether the CPM should offer payments for Flexibility.

Summary of comments received:

Mixed comments were received with the majority not supporting the flexibility payment option, while the remainder acknowledged that it is important to incentivise flexibility and wished to ensure that sufficient focus is placed on the development of new appropriate AS revenue mechanisms to reward flexible plant.

Several respondents strongly believed that any enhancement of the ancillary services payment stream should not be at the expense of the ACPS and that both the infra-marginal rent and ancillary service deductions to the Best New Entrant price are in place to prevent double-payment of fixed cost items. They also stated that the capacity pot should be used only to pay for capacity adequacy not system flexibility.

Respondents also commented that the CPM and AS have two separate and distinct objectives and that should remain. Adding greater complexity to the current design would be unhelpful and inconsistent with CPM objectives. Therefore they do not consider the CPM an appropriate mechanism to incentivise generator flexibility. They do recognise this is an important issue to address with increasing penetrations of wind going forward and suggest that it can be more easily achieved with greater transparency and focus through the ancillary services mechanism.

Some respondents were in favour of capacity payments for generator flexibility along the lines suggested in the Poyry flexibility payment scenario. They stated that the annual ancillary payments budget is a fraction of the Annual Capacity Payments Sum and is fully used for existing operational needs. As wind penetration increases there will be an increased need for generator flexibility in terms of fast starting and load changing, low starting cost and wide operating range. There will also be additional requirements that are not now supplied, such as for high inertia. The incentives that can be provided through ancillary services payments for these generator characteristics would be too low to attract them without a very significant increase in the ancillary services budget.

Most respondents stated that Ancillary Services are real services, which impose costs on generators and require payment; therefore, if additional services are required, the Ancillary Services pot should be increased. Some even suggested that in the longer term, they would like to see a competitive ancillary services market develop.

SEM Committee's Response:

The SEM Committee maintains its view that the CPM and the AS revenue payment streams have two separate objectives and that these should remain separate. The Regulatory Authorities will continue to work with the TSO to define additional AS services if required and the value of these services to the system as highlighted in the

Harmonised All-Island Ancillary Services Policy decision paper (SEM/08/013[18]). 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 may be better dealt 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.

12.2 CAPACITY PENALTIES

Within the SEM-11-019 paper the SEM Committee stated that they were strongly minded to consider an appropriate mechanism for penalising generators for not providing capacity when they have declared that they would. Views were sought on what would be the most appropriate form and method of issuing penalties and further suggestions from respondents on the scope and nature of penalties options.

Summary of comments received:

17 respondents commented on this section with 10 in favour of the idea of developing an appropriate mechanism for penalising generators and 7 respondents were either not in favour or thought that the current mechanism of penalisation external to the CPM was sufficient. Several respondents believed that the current penalty mechanisms and test facilities open to the Transmission System Operators ("TSOs") are sufficient and adequate to incentivise generators to be able to generate when instructed to do so.

One respondent considered the suggestion in section 4.4 of Poyry's paper that older plant is unreliable and receives capacity payments even though their ability to deliver capacity to the system is unproven. They commented on a perceived problem of generators declaring themselves available but who fail to respond when called upon; they note that several stations are older than many on the system but have high levels of availability.

While not in favour of introducing additional excessive penalties into the market, one respondent acknowledges that it is reasonable that where payments are made for service provision, then for lack of provision of the service, payments should be recouped. It is appropriate that plants which are not normally dispatched are periodically tested. The fairest method would be explicitly penalising for each event where there was a failure. This could involve recouping some of the payments previously made or a change to the capacity credit of that plant.

A respondent also commented that any additional penalties would be excessively penal. They highlight that a generator loses capacity payments until it is able to resynchronise to the Grid, which can be up to 12 hours if the generator is considered cold. In addition, a generator is subject to penalties for tripping, short notice declaration and imbalance charges. All of these add up to a significant penalty for failure to be available. Overall they feel generators have sufficient incentive to be available as there are already subject to significant penalties when unavailable.

Some commented that excessive penalties will only serve to create excessive risk in the mechanism and discourage appropriate and timely entry to SEM. Others responses did not support the introduction of a further penalty mechanism, but stated that if one were to be introduced then would advocate that it should be accompanied by an independent appeal mechanism.

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

Some respondent have argued that the SEM does not have sufficient exit signals to both ensure that customers are getting value for money and that signals are sent to new investors. While recognising that certain older plant still provide a level of security to the system, one respondent believes that a penalty mechanism will provide a balance in rewarding efficient, useful capacity (whether old or new), while providing an exit signal to inefficient capacity.

Several respondent also agreed with the idea of a points system whereby a generator would receive penalty points based on the severity of the failure, points could be accrued over time and the number of points a generator would receive would increase with increasing number of failures to provide capacity when required. Upon reaching a designated number of points, the generator would be obliged to make a penalty payment. The financial penalties so collected should be redistributed to the generators that provided capacity during the period in question, thus rewarding those units availability.

SEM Committee's Response:

Penalties should in theory serve to give an efficient exit signal to serial offenders who cannot provide the capacity they are paid for when called to do so. All generation that makes itself available deserves payment for its contribution to capacity adequacy, but if the generation is not available when required then the generator should not be eligible for payment. A CPM penalty system which redistributes money from non-performing generators to performing generators would provide a signal to non-performing generators.

Payment structures that rely on self declaration and assumed performance in the absence of contrary evidence usually have penalty provisions. For example, in energy markets there are generally no penalties. If a unit fails to generate, it does not get paid. However operating reserve markets often do have penalties. This is because operating reserve is very often not called to show that it can produce. A generator declares it has reserves and gets paid for reserves, usually without any short-term test of whether it could perform. In instances where reserve is called on and does not perform, a penalty applies, as it calls into doubt whether past declarations of operating reserves sold was is representation.

However, the SEM Committee does not feel it is appropriate to introduce penalties to the CPM at this stage. In particular, in light of the Regional Integration work stream and the likely requirement that significant changes to SEMO's systems would be required to accommodate such penalties. The SEM Committee will continue to consider this issue in relation to the Generator Performance Incentive (GPI) programme, which are intended to optimise generator capabilities based on the Grid Code standards resulting in reduced power system costs.

12.3 NEW ENTRANT SCENARIO

As highlighted in Option 6 in Work Package 7 - BNE Calculation Methodology paper, the SEM Committee along with its consultants investigated how a new entrant guarantee could be applied in the CPM. The ways to provide a new entrant guarantee highlighted in the paper included:

- Guaranteeing the BNE price at the time of commissioning for all new entrants adjusted by capacity credits, for a few years, and leaving the residual pot to be allocated among existing generators;
- Guaranteeing a BNE price only to conventional generators for a period of several years, and allocating the residual to renewable and existing generators.

The New Entrant Scenario, which is in Section 8 of the Poyry Report[19], assessed the impact of creating a separate new entrant pot from the Annual Capacity Payment Sum (ACPS). In this Scenario each new entrant was guaranteed a BNE price for 5 years, adjusted by de-rated capacity credit. The total sum of this guarantee is deducted from the ACPS. The remaining sum is allocated according to the re-balancing scenario on the basis of (a) a 50:50 split of the overall capacity pot between ex-post and ex-ante payments; (b) setting the flattening power factor to 0.5; and (c) dividing ex-post payments into current monthly pot weightings while ex-ante payments are applied similarly across all trading periods.

The SEM Committee asked for comments on the feasibility of introducing a new entrant guarantee and whether these New Entrants should be treated differently to incumbents in the CPM. 17 Respondents comment on this section of the paper with 4 in favour of introducing a new entrant guarantee and 13 disagreeing with the idea and stating that all units should be treated equally.

Summary of comments received:

One respondent considers that special treatment for new entrants should only be offered if a capacity shortfall is identified; and should be a separate pot from existing generators ACPS. Another commented that if introduced as suggested by Pöyry, the CPM payment for a new entrant should be fixed for 5 years. Moreover, this additional incentive should only apply to conventional generation. Another respondent stated that curtailing new entry may appear to be contrary to EU Competition Rules.

Most respondent agreed that all units should be treated equally. Several commented that they do not support the concept of a new entrant guarantee as it discriminates against existing generators who are providing the same service. One respondent argued that the introduction of such a guarantee would require the SEM Committee to change the objectives of the CPM which would lead to regulator risk and uncertainty associated with operation in the SEM. Another respondent believes that the technical ability of the plant to reliably and verifiably deliver the contracted services should be the basis for any incentivisation and age should not be a factor in this decision. Incentivising additional new entry may lead to inefficient and expensive market entry if new entry is encouraged at a price over and above that which can be provided by existing plants.

SEM Committee's Response:

While the SEM Committee does see both merit and risk in introducing the New Entrant Scenario, the SEM Committee has decided not to pursue this option at this stage. This option could encourage inefficient exit for existing generators and may increase regulatory risk. In addition, it is likely that major changes to the SEM Trading & Settlement Code and the existing principles and objectives of the CPM may be required.

13 WORK PACKAGE 9 - TIMING AND DISTRIBUTION OF CAPACITY PAYMENTS

The SEM Committee are of the view that capacity payments should remain valued at the best new entrant peaking price and weighted across the trading periods of year and day. Actual capacity at the demand peak or more specifically the 'margin valley' is more valuable to the system than the capacity at other times.

[1919] http://www.allislandproject.org/GetAttachment.aspx?id=7440e0f4-a8d1-47b0-baba-87551201d0d0

The SEM Committee choose the current allocations in a desire to provide an effective short-term signal for generation, which does not introduce excessive volatility or uncertainty, while balancing this against the need to provide longer-term stability for investment and the other Objectives for the CPM.

The following section will highlight the current distribution of payments and indicate the findings of Poyry's report.

13.1 CURRENT DISTRIBUTION OF PAYMENTS

The current mechanism for distribution of the pot is defined in the Capacity Payment Factors Decisions Paper published in December 2006 (SEM-231-06)[20]. The CPM is split into 12 monthly pots based on a calculation involving Monthly Peak (MW), Difference from Min Load and a Monthly Distribution %.

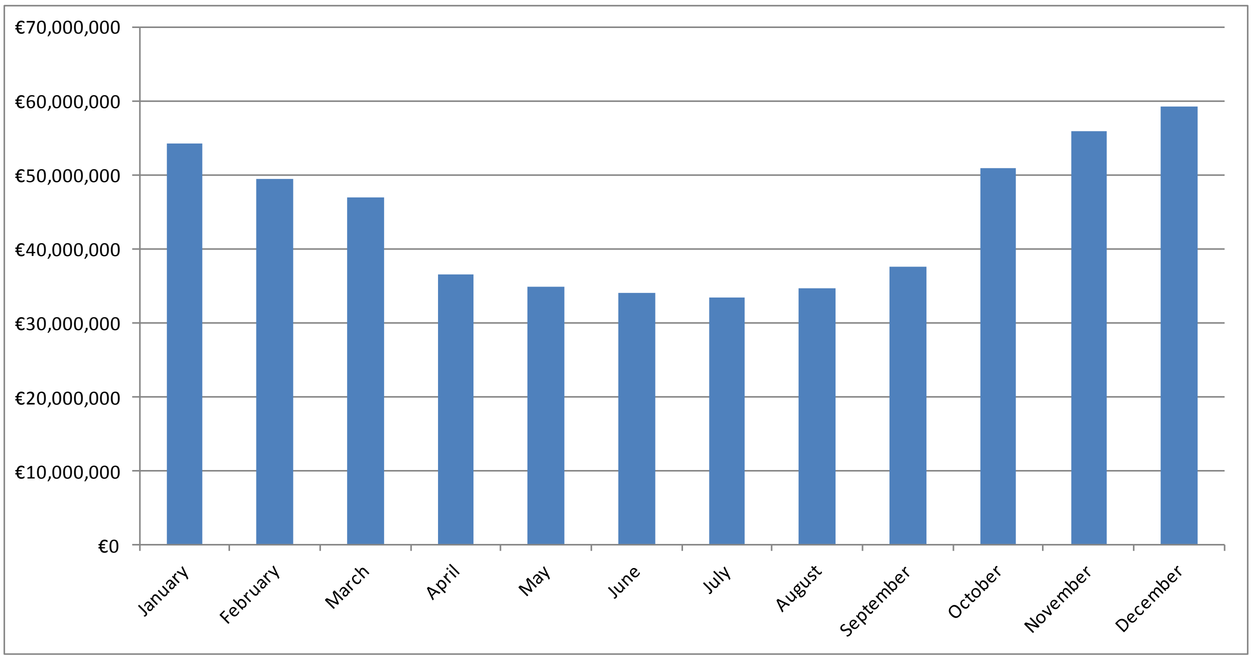

Figure 13.1 - 2012 Monthly Split

These are then further split into 3 payments, which have a Flattening Power Factor applied:

- **Year Ahead - Capacity Period Fixed Sum (currently 30%)** - Profiled into Trading Periods based on Forecast Demand in that Trading Period relative to the minimum Forecast Demand in the relevant Capacity Period. Profile determined before start of Year.
- **Month Ahead - Capacity Period Variable Sum (currently 40%)** - Profiled into Trading Periods based on forecast Loss of Load Probability in that trading Period relative to sum of forecast Loss of Load Probabilities for each Trading Period in the Capacity Period. Profile determined before start of Capacity Period.
- **Month End - Capacity Period Ex-Post Sum (currently 30%)** - Profiled into Trading Periods based on ex-post Loss of Load Probability in that Trading Period relative to sum of ex-post Loss of Load Probabilities for each Trading Period in the Capacity Period. Profile determined ex-post, after Capacity Period.

[20] http://www.allislandproject.org/en/capacity-payments-consultation.aspx?article=6f3e4fed-ee5b-48b8-99d5-08cc8a24116f

17 respondents replied to the discussion paper.

Summary of comments received:

Several respondents believed that the distribution allocation of capacity payments should be left unchanged. One respondent stated that to reflect the trade-off between long-term stability and short-term market signals the current split of the monthly capacity pots bet was established as the most appropriate balance between the competing objectives of the CPM. Another commented that the current split 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 and see no compelling case at the moment to change the weighting of these factors.

Another respondent commented that they would prefer a reduction in the ex-post allocation. They also stated that the uncertainty over the future of the SEM in the context of the target model means that it may be prudent to maintain the current allocations pending clarity on the future evolution on the wholesale market. Another respondent did not agree with the suggestion that capacity payments should move towards a more ex-post calculation, either under the 50/50 proposal or the SOCAP model. They state that the CP mechanism was designed to ensure stable and predictable payments to generators, and weighting the payment more towards an ex-post payment would make the payment more unstable and unpredictable for generators.

Another respondent stated that they believe the variable component neither delivers stability nor availability when the system needs it most. The reason for this is that the variable payments are weighted on a forecast of the margin. They believe that the variable component of the CPM undermines the signal for availability in the ex-post and also adds significant complexity to the mechanism. They suggest the dual objectives of the SEM could be better met with a combination of fixed and ex-post payments and that the variable component is not required.

Several other respondents believed that a move to a 50:50 ex-ante/ex-post weighting is a better allocation of the capacity taking into account the conflicting objectives. Other respondents favour this split for capacity payment calculation, with the ex-ante payment based on daily capacity pots (allocated month-ahead) and forecast loss of load probability.

Several other comments were received regarding moving towards a more ex ante weighted balance. There is, as the discussion documentation suggests, a balance to be struck between stability/certainty of participant revenues as provided by ex-ante weighting of payments and appropriate incentivisation of participants to be available at times of tight margin. Another comment stated that if anything the distribution allocation should be more heavily ex ante weighted because generators are unable to respond to an ex-post pricing signal, it would reduce the potential for gaming, and it would also be in keeping with the need for day-ahead coupling of the SEM and neighbouring markets under the emerging European Target Model.

SEM Committee's Response:

The SEM Committee continues to recognise that the Ex-Post element provides a degree of risk to generators since, unlike the Fixed and Variable elements, it is not known ahead of time and therefore retains a degree of uncertainty. However the Objectives for the CPM include the requirement to provide a short-term signal in the event of capacity shortages and the SEM Committee believe it is essential that such a short-term signal continues to be provided. The SEM Committee believe the balance between ex-ante certainty and the need to provide appropriate signals for the provision of short-term capacity response is best served by continuing the allocation of the ex-ante/ex-post split on a 70/30 basis as in previous years. Movements away from this balance between the ex-ante and ex-post elements could lead to one element swamping the signal from the other element.

The SEM Committee also recognise the need for stability in the longer-term signals so as to provide investor confidence as one of the aims of the mechanism should be to provide certainty to the investors, if they build reliable plants and maintain them properly, so that the plants are ready to produce and provide a product to consumers when needed.

The SEM Committee continues to consider the current allocation provides the best fit to the various Objectives of the CPM at this point in time. With the changing European landscape in mind the SEM Committee will take account of any changes and will consider these issues in due course.

13.2 FLATTENING POWER FACTOR ANALYSIS

As highlighted in the discussion paper SEM-11-019 a Flattening Power Factor (FPF) was introduced into the Loss Of Load Probability Table (LOLP Curve) calculation to have the objective of reducing the volatility in the Capacity Payments Mechanism. As the LOLP was considered to give rise to 'lottery' effects in months of high margin the SEM Committee wished to receive views on; should a FPF be continued to be applied within the CPM and if so, should the current value be maintained or changed. 13 Respondents responded with comments with mixed views.

Summary of comments received:

Several respondents were reluctant to move away from the current methodology, several had the view that no amendments should be made to the FPF. One respondent commented that they did not believe that the ex-post weighting should be increased as there is no evidence it has any bearing on the availability of capacity, however, if the ex-post were increased then the FPF should be reduced to dampen the volatility, thereby avoiding penalising smaller generators and advantaging portfolio generators. Another commented that the CPM was designed to ensure stable and predictable payments to generators, and weighting the payment more towards an ex-post payment would make the payment more unstable and unpredictable for generators. In their view, an increase to the flattening power factor would have the same effect, and is not desirable.

Another respondent suggested that there is merit in apply separate power factor's for ex-ante and ex-post, however they would reject an increase of ex-ante or ex-post power factors and they believe that there is merit in investigating a reduction in the ex-ante power factor. One respondent had suggested that in the context of daily capacity pots, they suggest that the Flattening Power Factor be increased towards a value of 1 to encourage capacity availability in times of tight margin. Other respondents had suggested mover towards an FPF of 0.5 as is a better compromise.

One respondent stated that the rationale for the FPF is that while it is reasonable to place greater value on available capacity at times of tighter margin, it is not the intention to introduce excessive volatility into the mechanism as this would undermine the stability objective of the mechanism. A FPF equal to 1 will result in a very steep LOLP function being used and therefore small differences in margin result in payment differences several orders of magnitude greater.

SEM Committee's Response:

Choosing an appropriate value for the Flattening Power Factor (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 during periods of high margin. The FPF shapes the LOLP curve to make it either 'steep' or 'flat'. Its purpose is to balance the level of volatility required to signal the need for availability in times of low margin and excessive volatility that would render the mechanism excessively unpredictable. The desire is to continue to keep some volatility in the payments to signal the need for availability during periods of system stress, but at the same time provide a smooth stream of payments over the course of the month.

The Flattening Power Factor in the Loss of Load Probability Table calculation has the objective of reducing the volatility in the Capacity Payments mechanism. Changing the FPF can be a potentially useful lever to alter the incentives under the current design, aligning the level of payments closer to system margin and providing incrementally higher payments to firm generators providing service when it is most needed.

The current FPF remains at the value of 0.35. The SEM Committee are minded to increase the FPF to 0.5 in 2013. This will also reward reliable plants more in line with their contribution to system scarcity. The TSOs will submit a review on the FPF in Aug 2012 to the SEM Committee; comments will be invited on these proposals put forward by SEMO and the TSOs in Sept 2012.

13.3 ALTERNATIVE APPROACHES TO THE DISTRIBUTION AND TIMING OF CAPACITY PAYMENTS

15 respondents commented on the **S**ystem **O**perator **C**apacity **A**llocation **P**rogramme (SOCAP) model which was developed by the Regulatory Authorities as an alternative approach to the distribution and timing of capacity payments. The majority of the comments received were against the introduction of this model.

Summary of comments received:

A respondent considered this methodology to lack transparency, be highly subjective and give too much control to the TSOs who could be conflicted by their ability to approve outage schedules. The independence of the TSOs in managing this model would be further eroded if the transmission assets are transferred to them in the near future as part of EU unbundling compliance.

Another respondent stated that a fully ex-post mechanism, such as the proposal espoused in the SOCAP model is entirely inappropriate from a cash flow and retail perspective as it inhibits product development, e.g. the provision of cost-reflective pass-through products.

One respondent stated that while the SEM Committee should be complimented for thinking outside the box in proposing this new approach there is an unacceptable level of uncertainty surrounding it and therefore could introduce an unacceptable level of regulatory risk. It would seem the proposal introduces additional layers of administration with reduced transparency. They suggested passing up on this proposal for now. Several respondents also did do not favour the proposed system, as they said it would increase opacity, uncertainty, trading risk and market costs.

Other respondents appreciated the intentions of the Regulatory Authorities in regard their SOCAP model, but they would not be in favour of such a model and believe that much of the benefits of such a model could be more efficiently realised using a combination of the fixed and ex-post payments with a higher value for the FPF.

SEM Committee's Response:

The SEM Committee have taken the comments of these respondents into consideration. The model was designed by the Regulatory Authorities to attempt to divorce the 'fairness' objective from the 'revenue stability' objective. As stated in various comments, the SEM Committee do not wish to radically reform the CPM at the moment, in particular with uncertainty surrounding the future of the SEM and the emerging European environment. With this in mind the SEM Committee will not be introducing or implementing the SOCAP model as an alternative approach to the distribution and timing of capacity payments.

14 WORK PACKAGE 10 - IMPACT OF CPM ON SUPPLIERS

This section of the SEM-11-019 discussion paper looked at aligning charges to suppliers with payments to generators. The Regulatory Authorities asked for comments from respondents / suppliers on options for shaping supplier Capacity Charges, in the context of the existing design. 11 respondents commented on this section. Several commented that as they are not directly involved in the supply side of the SEM, they will not comment on this work package in detail other than to say that it would appear logical to align capacity charges with capacity payments in order to signal the true time cost of demand.

Summary of comments received:

Some respondents did not believe that it is necessary to more closely align supplier capacity charges with capacity payments on a half-hourly basis. One respondent stated that in the current mechanism, the supplier changes broadly follow the same curve as the generator payments but are not equal. In an ideal world with real time metering data, both the charges and the payments would be equivalent and this would be used to improve efficiency and demand management. However, currently this is not possible with installed technology and thus they would recommend leaving the existing algebra as is. Another respondent commented that they are unsure whether customers would be sufficiently informed to correctly interpret the signal of the true time-varying cost of their consumption decisions.

One respondent commented that any market changes allow greater opportunities for both suppliers and pumped storage generators (when pumping) to provide demand side management.

One respondent commented that in theory Capacity charges to demand should track payments to generators since both determine margin at any given time. They highlight that the supplier charges are flatter such that night time chargers are higher and peak charges are lower. They believe that the profiling of capacity payments should be more heavily weighted towards periods where plant margins are tighter.

Another respondent stated that there is merit in considering the alignment of capacity charges with capacity payments. However it was their view that such a move cannot be made independent of significant developments in a number of other areas. The more serious difficulty relates to the practicality of consumers being able to respond to such price signals. There is no value in signalling if the intended recipients cannot respond to such.

A respondent commented that in the SEM currently there are quite significant price differentials between peak and non-peak electricity in the energy market, yet there is weak evidence that this has signalled much change in consumption patterns. A number of factors contribute to this, the ex-post nature of the market being one. But fundamentally given that while the Regulatory Authorities view the SEM as now mature, the associated retail markets are not, with the outcome that sufficient competition has yet to firmly take hold and drive the development of differentiated products to encapsulate those signalling. Beyond the development of such products progressively following from the maturation of retail markets, the workstreams on Smart Metering and Demand Side Response also indicate that the tools to provide visibility of electricity price signalling as well as enable a rational response to them are still largely not readily available to consumers.

Another respondent stated that while they agree with the theoretical underpinnings of economic utility maximisation, they would counter that it presupposes more elasticity (otherwise response-ability) on the demand side. Their experience is that customers want more certainty over costs in the current difficult trading environment. More ex ante weighting of capacity payment streams would help to provide this. But, whilst theoretically desirable to match payment profiles, it is difficult to see the practical benefits of doing this for the foreseeable future given the cost and complexity involved and the general inability of customers to respond to the signal.

SEM Committee's Response:

The SEM Committee agree with most of the comments obtained from the responses, at this point in time they do not believe that it is necessary to more closely align supplier capacity charges with capacity payments. Given the changes in the investment environment and the EU legislative environment for energy, most respondents would recommend leaving the existing algebra as is. As the installed technology and the workstreams on Smart Metering and Demand Side Response develop, these will enable the tools to provide visibility of electricity price signalling to consumers to respond to price/signal fluctuations. The SEM Committee recommend leaving the existing algebra unchanged.

15 CONCLUSIONS

The SEM Committee continues to consider the CPM as a key feature of the SEM design and that the concept of the CPM should remain in place. This mechanism was introduced at the start of the SEM as the best fit system that incorporates the following CPM objectives;

- Capacity Adequacy/ Reliability of the system
- Price Stability
- Simplicity
- Efficient price signals for Long Term Investments
- Susceptibility to Gaming
- Fairness

The CPM review assessed the objectives of the CPM to ensure they were being met in an appropriate manner. As previously stated, ongoing development of SEM and the CPM was always anticipated by the Regulatory Authorities during its development. It is judged that to date, and likely in the medium term future, the SEM is working well, that there are known challenges ahead but that for now these can be met whilst continuing to meet the SEM Strategic Objectives and the CPM Objectives **without fundamentally redesigning the SEM.** The SEM Committee did not wish to choose options that are disproportionately expensive or different to the current design relative to the benefits the changes would create. The SEM Committee believe that the current CPM is generally working well and that there is no compelling need to make major changes to the current design and methodology but there is a requirement to make some minor changes.

The SEM Committee agrees with respondent's comments that the landscape has changed since the review began; this includes changes in the investment environment, the legislative environment, the Third Package, the EMR and the European Framework Guidelines and Network Codes. The SEM Committee are aware that there will be consideration in the near future for developments towards agreement and to ensure compliance on the target model for a European electricity market model, if fundamental changes to the CPM High Level Design are envisaged these will be further consulted upon.

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. With this in mind 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, to ensure that participants have every opportunity to influencing the SEM / CPM development in line with the European guidelines and codes and to ensue that these parameters continuing to meet their intended objectives.

Key highlight points from the CPM Medium Term Review are;

- 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%.
- 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.
- The introduction of penalties will be considered in line with GPI's.
- SEM Committee are recommending increasing the Flattening Power Factor (FPF) to 0.5%.

Whilst the SEM Committee believe that given the current environment and the potential for future development of the SEM, the changes detailed above are the most appropriate at this point in time.

15.1 NEXT STEPS

It should be noted that these are draft decisions and the Regulatory Authorities will be publishing a decision paper in Q1 2012 before the 2013 BNE calculation process begins.

Views are invited regarding any and all aspects of the draft proposals put forward in this draft decision paper, and should be addressed (preferably via email) to Jody O'Boyle at jody.o'boyle@uregni.gov.uk by **5pm on 22nd December 2011**.

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