Single Electricity Market

Capacity Payment Factors

Ex-Ante Margin Decisions Paper and Response to Detailed Comments

AIP-SEM-07-54

26th March 2007

TABLE OF CONTENTS

1. INTRODUCTION

On 5 October 2006 the Commission for Energy Regulation and the Northern Ireland Authority for Energy Regulation ("the Regulatory Authorities") published a consultation paper entitled *"Capacity Payment Factors"*[1]. This paper considered a number of issues required to be resolved to finalise the details of the Capacity Payment Mechanism (CPM). The paper set out the issues and discussed a number of options for addressing each issue, in each case setting out the pros and cons and indicating the options which the Regulatory Authorities were minded to select in relation to some of the issues. Comments were invited on the issues set out in the consultation document by 2 November 2006. Responses were received from eight organisations and the non-confidential elements of these responses were published on the AIP website on 13 December 2006.

On 22 December 2006 the Regulatory Authorities published their Decisions[2] in relation to the matters considered in the consultation document and highlighted that further work was being undertaken in relation to two matters – the Loss of Load Probability curve to be used in the CPM and the determination of the ex-ante margin. This paper sets out the Regulatory Authorities' decisions in respect of the determination of the ex-ante margin and also provides the detailed responses to all of the comments received to the Capacity Payment Factors consultation paper.

The structure of this document is as follows:

> Section 2 sets out the background to the development of the CPM and the Capacity Payment Factors consultation paper; and

> Section 3 considers the responses relating to the derivation of the ex-ante margin for the purposes of calculating the LOLP values (λ_h) used to apportion the Capacity Period Variable Sum ($CPVS_c$).

In section 3 the key points raised in responses are summarised followed by the Regulatory Authorities considerations and conclusions.

In addition there are two Appendices:

> Appendix A contains a summary of the approach to be used to "schedule" capacity for energy limited and pumped storage units; and

1 http://www.allislandproject.org/2006/AIP-SEM-161-06.pdf
2 http://www.allislandproject.org/2006/AIP-SEM-231-06.doc

Appendix B contains the detailed responses to all of the comments received in relation to the Capacity Payment Factors consultation.

2. BACKGROUND

On 15th July 2005 the Regulatory Authorities issued a paper titled "*Capacity Payment Mechanism and Reserve Charging High Level Decision paper*"[3] in which the Regulatory Authorities stipulated their intention to develop a fixed revenue capacity payment mechanism which would provide a degree of financial certainty to generators under the new market arrangements and a stable year-to-year pattern of capacity payments.

The principles outlined in the July 2005 paper were incorporated into the design of the CPM in the all-island Trading and Settlement Code (T&SC) and on 21st December 2005, the Regulatory Authorities published a draft version (version 0.10) of the proposed T&SC for the SEM, with comments invited by 20th January 2006. Subsequent to the publication of this document the Regulatory Authorities determined that a more detailed consideration of the comments received on the design of the CPM was required and on 3rd March 2006 the Regulatory Authorities issued a further consultation paper[4]. Following a further open forum discussion the Regulatory Authorities issued a Decision document in July 2006[5] which described the selected CPM and attached a set of associated changes required to the T&SC version 1.0.

On 5 October 2006 the Regulatory Authorities issued a further consultation on a number of further detailed matters relating to the design of the CPM which had not been addressed by the consultation issued in March 2006. Decisions in relation to these matters were published by the Regulatory Authorities on 22 December 2006, however two elements (Loss of Load Probability Curves and the determination of the ex-ante margin) were not included in this Decisions paper as further work continued on these areas.

On 13 February 2007 the Regulatory Authorities published a consultation document seeking views on the Loss of Load Probability Curves[6] to be utilised in the CPM. The deadline for comments on this paper was set as 13 March 2007.

This paper sets out the decisions of the Regulatory Authorities in relation to the ex-ante margin and also provides detailed responses to the comments received on all the matters addressed in the Capacity Payment Factors consultation.

[3] http://www.allislandproject.org/2006/AIP-SEM-53-05.pdf
[4] http://www.allislandproject.org/2006/AIP-SEM-15-06.pdf
[5] http://www.allislandproject.org/2006/AIP-SEM-95-06.pdf
[6] http://www.allislandproject.org/2007/AIP-SEM-07-10.pdf

3. DETERMINATION OF THE EX-ANTE MARGIN

3.1. Introduction and Outline of Proposals

The margin for the determination of the ex-ante LOLP (used in the allocation of the Variable element of the Annual Capacity Payment Sum) needs to utilise forecast data for demand and availability, such forecasts needing to be determined prior to the start of each Capacity Period (month).

The Regulatory Authorities proposed in the consultation document that the production of a suitable forecast for demand by the TSOs was considered to be appropriate for these purposes but highlighted a number of issues in relation to the determination of a suitable forecast of availability. These issues arose because Generators do not routinely provide information on availability to the TSOs on timescales consistent with the determination of the ex-ante margin, other than for outage planning purposes.

Of the possible options which exist, the Regulatory Authorities proposed an approach similar to that for the determination of the Capacity Requirement. This approach takes a capacity value for each Generator Unit and adjusts the availability to account for planned outages (using the latest data available from the Planning process) and forced outages (using Forced Outage Probabilities – FOPs – based on historic data).

Other possible options described in the consultation document were to devolve responsibility to the TSOs to derive their best forecast of the margin at the month-ahead stage or to ask the Generators to submit a month-ahead availability profile.

3.2. Responses

As highlighted in the Capacity Payment Factors Decision document published on 22 December 2006, no objections were received to the Regulatory Authorities proposal to determine the Generator Unit Availability to be input to the ex-ante margin calculation based on the approach adopted for the determination of the Capacity Requirement – i.e. establishing unit capacities and modifying these to reflect planned outages and historic forced outage rates. Consequently the Regulatory Authorities concluded in the aforementioned Decision document that such an approach would be employed. However the Decision document highlighted that the precise details of the approach required further work with the TSOs. These considerations are given in the next section.

Two respondents said the approach to the derivation of the demand forecast should be published while two further responses raised concerns over the errors which could exist within the forecast, one stating that the methodology should not give rise to any systematic bias. Two respondents suggested that there should be a compensation mechanism in place for Generators who are required to move planned outages and as a consequence receive lower payments under the CPM than they would otherwise have done. But most comments related to the proposal to use FOPs based on use historic data, with three respondents suggesting there was a need for explicit rules for the determination of FOP values, one suggesting that such rules should utilise EPUS output rather than metered generation because of the impact of constraints on operation, and three suggesting that FOPs based on historic data should also be used for the determination of the Capacity Requirement, rather than the proposal to utilise average FOPs based on NI plant only.

3.3. Consideration of the Responses

As noted above the Regulatory Authorities have previously determined the overall approach to be used in determining the ex-ante margin, which in summary determines a forecast of the margin for each Trading Period in a Capacity Period (month) prior to the start of such period by:

- Identifying a unit capacity for each Generator Unit;
- Modifying this capacity for each Generator Unit to reflect any periods of planned outages;
- Further modifying the resultant capacity for each Generator Unit in each Trading Period by reference to a Forced Outage Probability (FOP);
- Aggregating the resultant capacities for each Trading Period;
- Comparing these aggregate capacities against a demand forecast by the TSOs for each Trading Period; and
- The difference between the derived aggregate capacity and forecast demand is determined as the ex-ante margin and will be used to determine the Loss of Load Probability for each Trading Period (λh) by

reference to a LOLP vs Margin look-up table, such values of λh being used to allocate the Capacity Period Variable Sum into each Trading Period for such Capacity Period.

The following sections consider each of the various input data outlined above to be used in deriving the ex-ante margin and the methodology to be employed for deriving such data. In addition each of the responses identified in section 3.2 above are given consideration and the resultant decision of the Regulatory Authorities is provided.

The detailed methodology based on the mechanism described in this Decision paper will be captured within Appendix M of the next version of the Trading and Settlement Code which is due to be issued at the end of March.

3.3.1. Which Generator Units to Include?

For the purposes of determining the ex-ante margin, only Generator Units eligible to receive payments under the CPM should be included in the generation "stack". This is consistent with the approach being taken for the ex-post margin and also for the Capacity Requirement, on which this approach is based.

3.3.2. Determination of Input Availability

Generator Unit availability input into the ex-ante margin calculation will be initially set equal to the capacity for each Generator Unit (Generator Unit output capability at the connection point less Unit Load). The Trading and Settlement Code requires the provision of Registered Capacity for Generator Units except Interconnector Units, Interconnector Error Units and Interconnector Residual Units. The submitted values of Registered Capacity will therefore provide the starting point for determining the forecast availability for all Generator Units – note that Interconnectors will be dealt with separately below. In the event that a Registered Capacity is not provided for a particular Generator Unit an appropriate value from the relevant Grid Code will be utilised (c.f. Maximum Generating Capacity Sent Out, defined in Schedule 1 of the Data Registration Code in the SONI Grid Code, and the Normal Maximum Continuous Export Capacity defined in section PC.A4.3 of the Eirgrid Grid Code).

The determination of the unit capacity for some Generator Units requires further consideration. The following sections address these unit types and explain why it is necessary to give further consideration toward the determination of their unit capacities.

a) CCGT Units

For the purposes of determining the ex-ante margin, the availability of Generator Units that are of Combined Cycle Gas Turbine (CCGT) construction (hereafter referred to as CCGT units) will be modified to reflect the impact of variations in temperature on their capacities. The TSOs have advised that such temperature effects are not material for unit types other than CCGT units. The approach will be for the TSOs to examine monthly mean temperatures over a historic period together with CCGT availability to establish the correlation. This will allow for the production of a temperature correction table for typical CCGT plant which will be used to apply adjustments to CCGT capacities. This table will be determined on an annual basis and applied for each Capacity Period in the next following year.

b) Energy Limited Generator Units and Pumped Storage Units

Energy Limited Generator Unit and Pumped Storage Unit availabilities will be derived by reference to the submitted Registered Capacity values as for other units but in order to forecast their likely availability over the month (which is likely to be optimised around peak demand periods – on the basis that such peak demand periods are likely to coincide with peak price (SMP) periods), the availabilities of such units will be subject to specific hydro modelling so as to optimise their contribution to improving the margin at times of forecast stress (within the limits of the input data and the optimisation model). Optimising the availabilities of such units is consistent with the way in which these units are treated within the determination of the Ex-Post Margin and within the EPUS run, although the model to be used will differ since the purpose is to establish a forecast across a month and as such needs to use forecast data applied over a month. An explanation of the model to be used is provided in Appendix A.

c) Wind Power Units

The contribution of Wind Power Units that are registered as Generator Units under the Code will be assessed on an aggregate basis. The Registered Capacities will be aggregated to give a total Wind availability profile. This profile will be further adjusted by the application of a Capacity Credit which will be derived using the methodology utilised in the Generation Adequacy Report (GAR) as applied to the whole island. This will result in a "flat" value of forecast wind production for each month, though the aggregate quantity of Wind capacity may vary across the year as new Wind Power Units are commissioned. Other than the application of the Capacity Credit, it is not intended to account for the forecast error associated with Wind production in any other way.

d) Commissioning Units

The availability of Generator Units which are Commissioning (hereafter referred to as Commissioning Units) will be set to zero for the purposes of determining the ex-ante margin. This is on the basis that the availability of such units is not known at the month-ahead stage. This will persist until the unit officially completes Commissioning (as determined under the Connection Agreement), whereupon the unit will be treated in accordance with its class (i.e. “normal”, Wind, CCGT etc.) from the first month following completion of Commissioning.

e) Units Under Test

In the Trading and Settlement Code in relation to the Capacity Payment Mechanism, a Unit Under Test has a similar status to the way in which a Commissioning Unit is to be considered for the purposes of determining the ex-ante margin – i.e. its availability is unproven and therefore its CPM payments are based on the minimum of its actual metered generation and its instructed output.

For the purposes of calculating the ex-ante margin it is therefore intended to assume units under test (under the Grid Code) are not available for the duration of the test period (which might be the whole month or just a specified period). It is possible for a Generator to request a test but to agree with the TSO that the precise scheduling will be under the control of the TSO so as to fit in with system requirements (OC11.8 and OC11.9 under the SONI Grid Code and OC8.1.3 under the Eirgrid Grid Code refer). Under such conditions the availability of the unit would not be discounted and therefore under such circumstances it would be considered as being available.

f) Interconnector Units

To forecast the capacity available across Interconnectors at the month-ahead stage the approach will be to treat them as single entities rather than the summation of the various units associated with Interconnectors. This simplifies the forecasting process and avoids any judgement needing to be made on the possible trading positions of parties across the Interconnectors. This approach is considered reasonable since the actual capacity which could be made available even at the day ahead stage could reflect the transfer capability of the link if the owners of the various Interconnector units wished to commit capacity at specified prices into the SEM. This approach is consistent with the treatment of Interconnectors in the determination of the Capacity Requirement.

The Trading and Settlement Code requires the provision of Aggregate Import Capacity and Aggregate Export Capacity. These values will be used to determine the forecast availability of an Interconnector for the purposes of determining the ex-ante margin.

3.3.3. Outage Programme Data

The Outage Programme is finalised at the end of October each year. In determining the ex-ante margin it is this agreed Outage Programme which will be used as the basis of the adjustments to the unit capacities in order to derive the input Generator Unit availability as outlined at the start of this section 3.3.

Following finalisation of the Outage Programme, modifications can be made through discussion between a Generator and the relevant TSO. Such modifications are provided for under OC2 of both Grid Codes. If such modifications have been agreed with the TSOs in advance of the calculation of the ex-ante margin for a particular Capacity Period, the TSOs will reflect this within the ex-ante margin determinations for that period and subsequent periods in the year. The intention is for the impact of the Outage Programme upon Generator Unit availability input into the margin calculation to be as up to-date as possible, once such data has been subject to the necessary levels of validation.

The TSOs will continue to monitor and record outturn outages against the Outage Programme and escalate any matters as necessary in accordance with the provisions of the respective Grid Codes (OC2).

Some respondents proposed that compensation should be provided in the event that an outage is moved following a request from a TSO and that movement resulted in a reduction in the Generators' payments under the CPM. Since the submission of these comments the Regulatory Authorities have issued their consideration of this issue in the decision document referring to the planned outage process[7]. Furthermore the Regulatory Authorities note that any consideration of the impact of a movement in planned outages affects both the energy (SMP) and capacity market payments and would therefore need to be considered in the context of the market as a whole.

[7] http://www.allislandproject.org/2007/AIP-SEM-236-07.pdf

3.3.4. Forced Outage Probabilities

The Availability of each Generator Unit and Interconnector as determined in accordance with the above will be further adjusted by a Forced Outage Probability (FOP). The FOP will provide a simple multiplier to adjust down each Generator Unit/Interconnector availability to account for the probability it may fail during the month. Separate values will be determined for each Generator Unit and Interconnector on an annual basis. These values will be based on a 5-year historic view of forced outages for the relevant Generator Unit/Interconnector. Note that a Forced Outage is defined as any period of unavailability (including a partial reduction in availability) that occurs and which is not identified in the agreed Outage Programme. In the event that a Generator requests an extension to an existing outage period in the agreed Outage Programme and that extension is agreed by the TSO(s) then such extension is not considered a Forced Outage. If such an extension is not agreed and the Generator still takes the outage, it will contribute to the Forced Outage value.

One respondent suggested that in determining FOP values the process should utilise the output from EPUS rather than metered generation in order to account for constraints. The Regulatory Authorities agree that using metered generation to determine FOP values would be misleading since any constrained down operation would be seen as a forced outage. In determining the values of FOPs the Regulatory Authorities intend to use a measure of availability rather than production in order to avoid the issue with constraints identified by the respondent.

A number of other respondents questioned why the approach of using historic data for each unit was not to be applied for the determination of the Capacity Requirement. The Regulatory Authorities have set out their determination in respect of the Capacity Requirement[8] which uses a historic average of FOPs associated with plant in NI as the basis for setting a target FOP for all plant on the island of Ireland (other than for Interconnectors since these are not like other a generating units). In establishing the Capacity Requirement, the volume element of the calculation of the annual sum of money to be collected/paid under the CPM, the Regulatory Authorities have made clear their intention to establish a target value of capacity so as to encourage improvements in availability in the medium term for poor performing plant. Furthermore the Regulatory Authorities consider that in setting the annual sum of money, it would be incorrect to effectively reward the poor performance of plant by inflating the sum of money to

8 http://www.allislandproject.org/2007/AIP-SEM-07-13.pdf

reflect actual FOP values. However in forecasting the ex-ante margin the Regulatory Authorities consider that using a unit specific estimate of FOP to be representative of the likely outcome in any given month and therefore more likely to provide a more accurate estimate of the actual margin. However given the variability of FOPs from year to year the Regulatory Authorities consider that some form of historic average would provide a more representative value. It is for this reason that FOPs will be determined over a 5 year period for each unit.

In calculating the Forced Outage value for a unit (or Interconnector), the number of days the unit was on scheduled outage will be accounted for first – i.e. the Forced Outage Probability for a given year will be the percentage of time the unit was not available at its unit capacity having netted off the time the unit was on scheduled outage.

Where a unit is newly commissioned it will be given a Forced Outage Probability which is representative of the average expected first year FOP for all units in its class – for example a new CCGT will have an FOP assigned to it based on the expected average of the first year FOPs of all CCGTs on the island. This same process will apply until the fifth anniversary of the completion of Commissioning for the Generator Unit. After this time the FOP will be calculated as for all other units. At the start of the SEM the same principles will be applied for any Generator Units with less than 5 years commercial operation.

Some respondents suggested that the rules for the determination of FOPs should be clearly specified. The next version of the Trading and Settlement Code (due for publication at the end of March) will contain a draft of Appendix M. The rules for the determination of FOPs will be contained within this appendix.

3.3.5. Demand Forecast

Consistent with the above it is necessary that the Demand Forecast should be a forecast for that demand to be met by market registered generation.

As for the determination of the Capacity Requirement, the intention is that each TSO will forecast its demand separately in order to reflect the drivers relevant for their respective jurisdictions. These forecasts will then be summed to provide an all-island Demand Forecast for the purposes of determining the ex-ante margin.

The TSOs have been asked to provide further detail of the proposed forecasting process for inclusion in the Trading and Settlement Code (in Appendix M). The following summarises the intended approach.

Both TSO will produce a forecast of the peak for the coming year based on a linear regression analysis of the peaks from previous years. A number of historic years will be examined and these will be flexible in order to reduce errors and maximise forecast accuracy.

Temperature correction of this forecast peak will be examined to determine if there is any benefit in terms of accuracy.

The annual peak forecast will be decomposed into weekly peak forecasts by examining the ratio of each weekly peak to that of the yearly peak from previous years.

Each day of the forecast year will be classified as one of several standard day types. These standard day types will consist of a normalized trading period level profile along with a scalar multiplier which determines the peak of that day as a fraction of the corresponding weekly peak.

These standard daily profiles along with their associated multiplier will be determined by analysis of historical demand data and will be representative of demand patterns for a particular time of year, day of the week, weekends and for special holidays.

No additional processing is proposed to be carried out on the demand forecasts in addition to what is described here (i.e. no smoothing). Integral to the annual process of determining the forecast for the year to come is a review process of the performance of the previous year's forecast in order to produce the best possible forecast for the year ahead. This will involve analysis of the annual peak demand forecast accuracy and, the weekly demands forecast accuracy.

Finally forecast production from non-market registered generation will be netted in a consistent manner from the demand forecasts by both TSOs.

The draft Appendix M to be included in the next version of the Trading and Settlement Code will contain the above process for the derivation of a forecast of demand for the determination of the ex-ante margin.

APPENDIX A – OPTIMISATION OF ENERGY LIMITED AND PUMPED STORAGE UNIT CAPACITY

In order to estimate the contribution towards capacity from energy limited plant and pumped storage plant (hereafter referred to as energy limited plant) it is intended to optimize the contribution available from such plant. This appendix provides an overview of the algorithm to optimize this contribution. The algorithm seeks to maximize the margin over the optimization day and is based on the CAPPAY calculation specification document, version 1.7.

The approach will allocate forecasted available energy from energy limited plant for each calendar day in an optimal fashion so that the minimum margin is maximized as follows:

Loop for each day

Continue while there is remaining energy in any station.

Find the period(s) of minimum margin and the number of periods of minimum margin

Loop for each energy limited station

1. Increase the optimised production from current station for each period of minimum margin by 1MW divided by the number of minimum margin periods, except if there is not sufficient remaining energy for this station to do this. If there is insufficient energy to do this, increase the optimised production from that station by the remaining energy divided by the number of minimum margin periods.

2. If increasing the production for a station for any period in the step above would result in a violation of the station's availability, only increase the production in those periods by an amount that would not violate station availability. If station is already at it's availability in previous step, do not update production.

3. Update Remaining Energy for Station bearing in mind that for each MW of production allocated to a unit in a half hour trading period, 0.5MWh is deducted from the energy remaining for that station.

4. Update Margin in all periods

5. Find the period(s) of minimum margin and the number of periods of minimum margin

Loop to next station

Loop to next day

APPENDIX B – RESPONSE TO DETAILED COMMENTS

This Appendix sets out the comments received from respondents to the Consultation document on Capacity Payment Factors and the responses from the Regulatory Authorities. The comments are grouped by subject matter for ease of consideration. Note that only points of contention are raised in this summary, comments made which agree with proposals or analysis set out in the consultation are not included.

Document Title:	**Capacity Payment Factors**
Document Ref Number:	AIP/SEM/161/06
Comments to be returned by:	02/11/06
Comments returned to:	Peter Halligan (peter.halligan@ofreg.gov.ni)
Document Author:	John Parsonage

Respondee	Heading / Comments	Response
	Determination of Ex-Post Margin	
ESB PG	PG supports the RAs proposal that the sum of Eligible Availability across all units eligible to receive Capacity Payments is used in calculating the margin for the purposes of the Capacity Payment Mechanism (CPM). However, PG is concerned that the paper differentiates between Actual Availability (AA) and Eligible Availability (EA) as version 1 of the T&SC states that these are one and the same for all units with full firm transmission access. Paragraph 4.41 states AAuh = APuh. Can the RAs please confirm that this is still the case.	The Trading and Settlement Code Version 1.2[9] confirms in paragraph 4.35 that for Generator Units with no Non-Firm Access AAuh = APuh.

9 http://www.allislandproject.org/2007/AIP-SEM-07-07.pdf

<table>
<tr><td>VPE</td><td>VPE tend to agree that generators used in determining margin are those eligible for capacity payments. The eligible availability approach appears consistent with this. VPE note however that further detail would be useful on how exactly pumped storage, energy limited plant, demand side participating units and interconnectors will be treated in detail.</td><td>The Trading and Settlement Code Version 1.2 provides the rules for the determination of the Ex-Post Margin within Appendix M. It further clarifies the determination of the Eligible Availability of Pumped Storage Units from paragraph 5.103 and Energy Limited Units from paragraph 5.90A. The rules for Eligible Availability for Interconnector Units and Demand Side Units remain unchanged in respect of the CPM.</td></tr>
<tr><td></td><td>Determination of Ex-Ante Margin</td><td></td></tr>
<tr><td>ESB CS</td><td>ESBCS disagrees with the following elements of the proposals:

• that the RAs should get involved in the detailed forecasting of monthly generation availability. ESBCS considers that this should be left to the TSOs – if the methodology is sufficiently well-defined (as suggested above) to remove the need for discretion, then there is no advantage to be gained from the RAs' involvement in this task.

ESBCS suggests the following additional measures:

• that the TSOs are asked to present to Market Participants how they plan to jointly produce their SEM system demand forecasts since these will be vital in determining many parts of the Capacity Price Mechanism (CPM) – there should be particular emphasis on:
o consistency of assumptions and methodology between the RoI and NI;
o consistency of treatment of demand met by de minimis generation within demand forecasts and within CPM generation availability calculations; and
o indication of whether the methodology is likely to deliver "realistic" or "smoothed" demand profiles and the likely impact on measured monthly peak demands;

• that explicit rules are developed for calculating FOPs for each existing unit based on historical data and for new units based on an average of FOPs for similar technology plants – these values should be updated monthly or seasonally to reflect recent historical plant availability.</td><td>As set out in this document the determination of the Ex-Ante Margin is to be undertaken by the TSOs in accordance with the mechanism set out in this Decision document.

The mechanism the TSOs will use to forecast demand is contained in the main body of this document.

The approach to be used for the establishment of FOPs is set out in this Decision document and reflects the comments raised here, though the Regulatory Authorities prefer to adopt values for a 12 month period. Further detail will be provided within Appendix M of the Trading and Settlement Code.</td></tr>
</table>

Synergen	Synergen accepts that the TSO's forecast of demand should be utilised. However, there should be regular reporting (by the Market Monitoring Unit) of demand forecast error. Synergen believes that there should be no systemic bias in the mean demand forecasting error over time, nor should there be any time of day variations in the error (i.e. an over forecast of peak and an under forecast of overnight trough). If there appears to be a systemic bias in demand forecasting error outside of a given tolerance (say ±1%) the RAs should give specific consideration to any corrections that would then be appropriate. One aspect of the RAs position that does concern Synergen is the argument put forward that whilst historic NI FOP data may be the appropriate form of FOP data for the determination of required capacity to calculate the CPM, it is more appropriate to utilise historic FOPs on a plant by plant basis for month ahead availability calculations. As noted in Synergen's submission on CPM Capacity Requirements, Synergen does not accept the use of NI FOP data for RoI gensets in any part of the CPM calculation process. Synergen has previously expressed concerns regarding the potential adverse commercial impact of the Grid moving scheduled outages from a lower CPM period to a higher CPM period. There is clearly an inherent difficulty in retaining a central outage scheduling process and placing incentives on generators to be available at certain times – particularly as generators rely on SRMC bidding plus CPM to be compensatory. Synergen believes that within a CPM period, once ex-ante payments are determined, a scheduled outage can only be moved with either the explicit agreement of the generator and that generators should be compensated for these changes. The most appropriate compensation payment stream would be through the imbalance charge. Synergen believes that there needs to be a fuller consideration of the interaction of the CPM and outage planning, and will also raise these in the context of the transmission outage planning consultation presently underway.	The TSOs undertake a review of the demand forecast versus outturn demand as part of the process for the development of the next years forecast. It would be expected that this process should identify if any bias existed overtime. The Regulatory Authorities have clarified their reasoning for the selection of a target based on historic average FOPs for NI conventional plant in determining the Capacity Requirement in the Decision document concerning the methodology for the determination of the Capacity Requirement[10]. The Regulatory Authorities consider the establishment of such a target for the determination of the Capacity Requirement and, therefore, in sizing the Annual Capacity Payment Sum to be correct if poor performance is not to be rewarded under the CPM. In seeking to forecast ex-ante the likely plant margin it is necessary to utilise data which is likely to give the most accurate forecast. Hence the use of historic average FOPs. Regarding the implications for moving Planned Outages, the Regulatory Authorities have responded to this specific issue in their document entitled Decision on Generation and Transmission Outage Planning[11]

10 http://www.allislandproject.org/2007/AIP-SEM-07-13.pdf
11 http://www.allislandproject.org/2007/AIP-SEM-236-07.pdf

ESB Int.	The RAs proposal to de-rate unit capacities by their own historical FOP seems reasonable but ESBI does not understand why a similar approach could not be applied to the Capacity Requirement. The various definitions applied to the various elements of the CPM are becoming quite confusing and give the impression that the RAs change definitions to suit their preferred outcome. It would help if the RAs could explain the period over which FOP will be estimated and what will apply to new plants under test or generators coming back after a major incident. ESBI notes the impact of the TSOs' demand forecasting on the determination of the ex-ante margin. Underestimates of demand at off-peak period, or over-estimates at peak periods could have a significant impact on generator CPM revenues. An indication of the current forecasting accuracy of the two TSOs would be helpful, as well as some discussion on how forecast accuracy will be monitored and systematic errors identified in the SEM. We suggest that, while this would be part of the joint TSO planning process, it should be in the scope of the Market Monitoring Unit.	See above answers in respect of these issues.
NIE	NIE commented in response to the previous consultation on the determination of the Capacity Requirement that the use of NI FOPs for all capacity is not appropriate and is relieved that that the proposal in this consultation paper is to use actual historic FOPs for each unit. The use in any part of the CPM calculations of FOPs that are lower than those that actually pertain endangers the security of supply. FOPs (and the measure of their variability used in compiling the LoLP calculations) should be derived from historical data.	See above answers in respect of this issue.
VPE	VPE consider that historical data is the best source for calculating FOP. The alternative of the TSOs or generators submitted data are both too subjective and possibly could introduce gaming concerns. It would be useful to clarify that historical data is from EPUS outputs rather than actual metered data as the two sets could diverge depending on the level of transmission constraints in the system. It would also be useful to define whether this is at the trading point or station gate (i.e. do TLAFs affect the results?). VPE support the idea of market monitoring to ensure that outage planning, particularly of a portfolio player, is not used to distort the market.	The Regulatory Authorities agree that using historic data will provide the best source for calculating FOP data. Furthermore the Regulatory Authorities agree that using metered generation would provide an incorrect representation of generator availability due to, among other matters, the incidences of constraints. Consequently the Regulatory Authorities have proposed to use a measure of availability at the station gate (exclusive of TLAFs) as the basis for determining FOPs.

	Determination of LOLP Values	
ESB CS	ESBCS **disagrees** with the following elements of the proposals: • that there is any advantage to be gained from using different look-up tables to calculate ex-ante and ex-post LOLPs. ESBCS considers that it is more important to have consistency between the determination of the ex-post and ex-ante LOLPs from the margin than to have the "granularity" of the look-up table reflect the "accuracy" of the margin calculation.	After further consideration the Regulatory Authorities are minded to agree with this matter and have indicated so in the recently published consultation paper on LOLP Curves[12].
Synergen	The central issue, from Synergen's perspective, is the slope of the LOLP curve used. In principle, Synergen believes that it would be unrealistic to create a distribution of payments (based on relative scarcity) that shifted material sums between periods where (in any realistic estimation) the likelihood of a loss of load due to a deficit of generation are negligible. Synergen is concerned with that the LOLP regime could allocate significant sums into a single period due to the relative nature of payment allocation. Accordingly, Synergen would welcome LOLP being set flat (i.e. at a small fixed positive number) above a predetermined margin level such as 3,500 MW.	As noted in the aforementioned LOLP Curve Consultation document, the Regulatory Authorities have conducted some modeling which suggests that the limit would need to be set much lower than 3,500MW – much close to 2,000MW in fact. This particular approach has the effect of diverting money away from peaks and flattening the overall profile, something which could be achieved more easily by increasing the size of the Fixed element of the CPM mechanism. The Regulatory Authorities have determined the apportionment between Fixed, Variable and Ex-Post elements and do not wish to reconsider this allocation. Further consideration of flattening is currently being given as a result of the responses received to the aforementioned LOLP consultation.
Bord Gais	The two LOLP Curves should be the same. If they can be changed by the regulator it can potentially provide a scope for shuffling money between parties;	The Regulatory Authorities are minded to agree that there should be a single LOLP Curve for both Ex-Ante and Ex-Post and have indicated so in the LOLP consultation, responses to which are currently being considered.
ESB Int.	In the interests of simplicity ESBI welcomes the proposal to make the LOLP values available as look-up tables to market participants, who are unlikely to be able to model LOLP themselves. We note the difficulty in arriving at LOLP curves which achieve the desired outcome and have some concerns about curves which are highly exponential. This could lead to most of the capacity payment being allocated to a small number of periods when the risk to customers of losing load leads to a disproportional risk to generators of losing revenues. ESBI awaits with interest future consultation on the outcome of the TSOs' Plexos modelling.	In the LOLP Curves consultation document the Regulatory Authorities set out a number of methodologies for the determination of LOLP curves and identify the one they are minded to adopt. The Regulatory Authorities note the desire expressed to smooth the LOLP curve in order to avoid LOLP allocating money into only a few periods but as highlighted in the consultation the Regulatory Authorities have difficulty in identifying alternative curves (i.e. not LOLP curves) which could justifiably be utilised and which could be repeatable year on year. Further consideration as to how such smoothing could be undertaken is currently being given in response to comments received on the LOLP consultation.

12 http://www.allislandproject.org/2007/AIP-SEM-07-10.pdf

NIE	The consultation paper leaves most of the discussion of the LoLP calculation to a later consultation, saying that look-up tables will be compiled from which LoLP values corresponding to a measured plant margin can be read. This seems reasonable but the LoLP calculations will depend on the standard error of the demand forecast (including that produced by weather) and the standard error in the availability forecast (i.e. the variation in, rather than the level of, forced outage rates). These may all change over time and so there should be provision for changing the tables as new assessments of these variables are made. It should also be noted that the LoLP will be very different depending on the combinations of capacity available. For example a plant margin of 800MW is very different when it exists at a time when all the 400MW generating units are already unavailable compared to a situation where they are all available (and other units are unavailable) and hence the breakdown of 2 units would result in load shedding. This sensitivity would be very difficult to capture from a single lookup table. It is suggested that there should be different look-up tables for the ex-ante and ex-post LoLP calculations. The concept of an ex post LoLP is a slightly strange one, since ex post it is either 0 or 1, but one can imagine that an ex post calculation might be done on the basis that some more of the independent variables are known. In this case, the weather is an example of something known ex-post but not ex-ante and an ex-post LoLP look-up table could be computed on the basis of a demand forecast standard error for a forecast under given weather conditions (e.g. average cold spell, ACS) and an availability forecast error that also excluded the weather component. These would be smaller than the ex-ante forecast standard errors and so would tend to make the ex-post profile flatter than the ex-ante profile, other things being equal. The paper also highlights the problem of “relative” LoLPs where they are low for protracted periods. This is a symptom of including ex-post relative LoLPs but the proposed “fix” will only serve to distort the CPM further and should be avoided	The Regulatory Authorities have identified in the LOLP consultation the possible need for recalculations to be undertaken in response to changes but are suggesting that these would only occur in the case of major changes such as plant entry/exit. Regarding different Look-Up tables the Regulatory Authorities have indicated in the LOLP consultation that they are minded not to pursue this option any further. The Regulatory Authorities are minded to agree that flattening of the LOLP curves as originally proposed is not desirable and are not minded to pursue this approach further, however other approaches are currently being considered in response to the comments received to the LOLP consultation.

VPE	The LOLP formulation to be used to derive the lookup tables to be used in the CPM are not defined. We understand that this area of work is still being reviewed by the TSOs but we urge that the modelling results and conclusions from this process are made available to market participants so that we can understand the affect it may have on our existing and potential future investments in the sector. From the footnote on page 14 it appears that a wide range of possible formulae ranging from exponential to linear are being reviewed. The paper rightly recognises that it is possible for a single half hour to have virtually all of the ex ante or ex post capacity value in a given month, and this could be in low or high demand periods. VPE note that volatility in capacity payments undermines stable investments, particularly where that volatility cannot be hedged, and suggest that mechanism to damp the volatility are worth consideration.	The Regulatory Authorities have considered a number of alternative derivations of LOLP and also alternatives curves. The difficulty with alternative curves is that they are, by definition, not LOLP curves and therefore more difficult to define and justify. As noted above the Regulatory Authorities are currently considering alternative approaches to dealing with the issue identified here regarding the possibility for large amounts of the monthly pots to be allocated into one or two Trading Periods and will bring forward their decision in due course.

	Longer-Term Measure of Availability	
Synergen	Synergen does not accept that because the modelling does not demonstrate that a gaming opportunity exists using short-term availability measures that this observation will necessarily hold true once the SEM goes live. Synergen continues to believe that only long term assessments of availability offer protection to non-portfolio players. AIP/SEM/161/06 states "***The results showed that in the vast majority of cases the generators revenue decreased…***"*1* supports the Synergen view that LOLP gaming could be profitable; indeed the only challenge for the well resourced portfolio participant is to identify those periods where availability withdrawal is a profitable strategy. Accordingly, Synergen concludes that as the possibility to manipulate payments exists, at some stage a party will profit maximise by exploiting the loop hole demonstrated by the positive value points within Figure 1 of AIP/SEM/161/06. Consequentially, Synergen believes that long term measures of availability should be based on long term availability values – such as a 3 year rolling average. This reduces gaming opportunities and provides a true reflection of a genset's availability.	The use of a longer-term measure of availability in the Ex-Post calculation has been considered by the Regulatory Authorities. A significant downside to using such a longer-term measure is that it will dull the signal provided through the Ex-Post element of the CPM. This is a key feature of the CPM and one which in the view of the Regulatory Authorities provides a strong, clear signal as to the value of capacity in each Trading Period. Using a longer-term measure of availability would dull this signal significantly and may call in to question its value. The Regulatory Authorities note the concerns raised regarding the potential for Generators (in particular portfolio Generators) to be able to game the Ex-Post allocation by withdrawal of availability. The modelling the Regulatory Authorities has undertaken has confirmed the initial modelling undertaken by the TSOs for the cases studied (these cases were described in the Capacity Payment Factors Consultation document) which showed that withdrawal of between 100MW and 1000MW for a large portfolio player in each Trading Period has very few instances which yielded a revenue increase for the Generator. This document shows the extent of the impact and notes that on the occasions when a positive impact was yielded it coincided with extremely low output from wind generation. Thus Generator would have to either forecast, or have knowledge of, forced outages of Generator Units owned by other Generators and would have to forecast Wind production at certain key times in the year to create circumstances from which it may benefit by withdrawing availability. Furthermore the results only consider the impact upon the Ex-Post element of the CPM payments – withdrawal of availability by a Generator would have a knock-on impact on its revenue from the Fixed and Variable elements too. Thus a Generator would be exposed to some considerable risk if it were to adopt such a strategy. Nonetheless the Regulatory Authorities recognise the possibility for some positive gains by such actions and part of the function of the Market Monitoring function will be to examine market data for instances of such gaming.

Bord Gais	The Market Abuse analysis that has been done is not detailed enough and further work should be commissioned – the requirement reduces as the Ex-Post % falls.	Further information on the analysis undertaken was presented in the Capacity Payment Factors Decisions document. The Regulatory Authorities note to comment regarding the size of the ex-post element but are of the view that the current allocation between Fixed, Variable and Ex-Post provides a good balance and are not minded to change the distribution at this stage (see later).
ESB Int.	On the bases of simplicity, consistency and transparency ESBI agrees with the proposal to use actual availability in the determination of ex-post LOLP. We were interested in the RAs' modelling of the impact on a portfolio generator of capacity with-holding, however, and would appreciate the publication of more details of this analysis. In view of the size of individual generation units in Ireland, and the proposed monitoring of SEM bids, the modelling of capacity withdrawal up to 1,000 MW seems to be unrealistic and may be masking the results of with-holding smaller amounts of capacity. There is no indication of the impact of capacity with-holding at the steepest parts of the LOLP curve, or of how much capacity the portfolio generators control. ESBI would like to see the results of capacity withdrawal of 400 MW down to 100 MW at the times of greatest demand for different levels of market share by the two biggest generators.	Further information on the analysis undertaken was presented in the Capacity Payment Factors Decision document. This noted that the positive values occurred with higher LOLP values but that these were also coincident with low Wind volumes. The modelling did cover withdrawal of 100MW to 400MW as suggested but also modeled larger withdrawals to see what effect they had. As noted above a Generator would need to predict Wind production, the status of other Generators and the possible impact withdrawal of its plant would have on LOLP/payments. Also, as noted above, part of the function of the Market Monitoring Unit will be to examine market data for instances of such gaming.
NIE	If capacity payments are to be affected by the actual outturn, the benefit of doing so is reduced if actual availability cannot be used. It is therefore encouraging that the RAs have found that in the vast majority of cases simulated generator revenue fell when plant was withdrawn and that they have therefore concluded that there is no need to alter the availability input (e.g. by using a longer term average). However, it is not clear from the analysis whether such results would still stand if the margin was tighter and outages were targeted. Further investigation of this issue should be conducted and the results must be influenced to some extent by the shape of the LoLP curves adopted.	See above.
VPE	VPE would be interested in the results of the study carried out on whether withholding plant can give a portfolio player an advantage in the market. The study appears to have considered the impact on revenue for the portfolio player but does not look at the relative position of the portfolio player to a single generator. If the portfolio player could withhold plant at minimal cost to itself but significantly reduce the revenue for smaller players who are seeking to take their market share, could this mechanism be used to damage competition? It is not clear whether this was addressed in the study.	The study did not explicitly seek to observe the impact on smaller players of a portfolio player withdrawing availability. Clearly with a fixed amount of money any loss incurred by a portfolio through plant withdrawal will be redistributed to the remaining available generators. It is possible that if a portfolio had knowledge that a smaller competitor was on outage it may withdraw availability to allocate more of the Ex-Post element into the period but if the portfolio would not gain financially by this action (which the study suggests it would not in the vast majority of cases) it is not clear that it would wish to do this. Also as noted above the market Monitoring function will be examining market data to identify any occurrences of such plant withdrawal. Together the Regulatory Authorities are of the view that this should provide sufficient safeguards.

	Determination of Capacity Period Payment Sums	
ESB CS	ESBCS suggests the following additional measures: • that the T&SC states that the Annual System Demand Forecast is produced "four months before the start of the year" consistently with other CPM parameters and as stated in draft Agreed Procedure 6: Data Publication;	Appendix Q of the Trading and Settlement Code Version 1.2 clarifies the timing of the publication of the load forecast.
ESB Int.	The analysis presented in the paper is described as being based on data utilised for a November 2005 CPM presentation to be found on the AIP website. ESBI cannot find a relevant document dated around this time on either the main AIP website or the modelling website and, in the absence of detail in the paper itself or of figures representing approaches (b) and (c), can only comment on the general description presented. The intention of profiling the CPM into monthly pots is to ensure that there are market signals to ensure the availability of capacity when required. This would be achieved by demand or margin weighting which could be regarded as a market signal, ESBI is concerned that the RAs are proposing to apply a more complex weighting on the basis that market signals would not be sufficient. This ignores the RAs' own analysis of the impact on portfolio generators of availability withdrawal as well as the fact that all generators who hedge their sales with contracts for difference and are then not available at times of high demand will be exposing themselves to the increased SMP at those periods as well as losing out on capacity payments. Complex weighting approaches could also be regarded by potential investors as further evidence of regulatory intervention in SEM price formation and increase perceptions of regulatory risk. ESBI is therefore in favour of approach (a) since it is stated that approach (b) produces inconsistently high summer values.	The data used in the November 2005 presentations was based on Plexos run data. Later versions of Plexos data are now available on the All Island Project website. Graphs detailing the impact of each of the four approaches were provided in Appendix C of the Capacity Payment Factors Decision document. This document also set out in further detail why the Regulatory Authorities selected Approach d. The Regulatory Authorities do not accept that using a more complex distribution function will give rise to an increase in uncertainty. Whilst the approach may be more complex than the three other options it is still a simple calculation which will be verifiable by all parties when the distribution and demand forecast is published each year. Given this it is unclear how this will lead to greater uncertainty.
NIE	The allocation of payments between months should incentivise generation to be present at the winter peak. It is surprising that weighting by margin produces a flatter annual profile than does weighting by the difference between monthly peak demand and annual minimum demand, which is the RAs' preferred option. Indeed, margin weighting is said to produce "relatively flat values". It would be helpful to see the details of the calculations, for example showing whether the weights used are margins or availability/demand ratios and illustrating how the profile might change as the annual margin varies. However, if the RAs are correct in the comparison of the profiles, NIE supports their conclusion.	Further details were provided in the aforementioned Decision document. Since one of the objectives of the Outage Programme process will be to achieve a sufficient plant margin throughout the year it should not be too surprising that profiling on the basis of the margin yields a relatively flat allocation.

VPE	VPE caution against an arbitrary setting of the capacity period sums where the approach adopted is to meet a specific outcome which may not reflect the underlying economic drivers. There is an obvious need to give incentive to generators to be available at times of peak demand and at its simplest a demand weighting or margin weighting should achieve this. The graph in figure 2 implies that demand weighting in July could actually be higher than January or February. We are confused at this outcome as demand is generally significantly higher in January than it is in July. VPE would welcome an opportunity to review the results of the study. How does the study results compare with the associated SMP prices, surely prices are much higher in January and February and that this in itself will be a stimulus to not maintain generators at the times of these high prices. A possible reason that there is not a large differentiation between winter and summer may be that older plants on the system that typically need a lot of maintenance. If all of this plant is replaced in the near term, and with a larger component of wind generation on the system, then perhaps the winter – summer differential will change. Are there models of future scenarios?	The aforementioned Decision document on Capacity Payment Factors provided further details of the modelling undertaken and shows clearly the results of the various approaches tested. The approach selected by the Regulatory Authorities does reflect underlying drivers since it is based on demand relative to the trough of the year.

	Fixed, Variable and Ex-Post Allocations	
Synergen	In principle, Synergen believes that the ex-post and ex-ante variable element should be zero and all payments should be fixed ex-ante, as generators' actual ability to respond to the envisaged "short term" signal is very limited. However, Synergen's approach to the SEM is always to propose realistic and achievable outcomes and as such would ask the RAs to consider the following alternatives values: • ex-post element 20%; • variable element 20%; and • fixed element 60%. Furthermore, Synergen would request that these values are captured within the T&SC and the RAs commit to a maximum ±1% change in allocations for subsequent years to signal regulatory certainty within the CPM.	The Regulatory Authorities have given careful consideration to the allocations between the various elements of the CPM. Matters such as the need to provide stability and predictability in Generator revenues while also giving signals for the value of capacity at any given point in time have all been considered. In particular the Regulatory Authorities looked to the Objectives for the CPM and the comments made by respondents to previous consultations on the CPM in which the need to minimise risks was emphasised in order to secure investment in the market. It is for these reasons that the Regulatory Authorities have decided to adopt an approach which ensures that the allocation of 70% of the total CPM monies is known prior to each Trading Periods. Of this 70%, the allocation of almost half will be known prior to the start of the year, with the balance being allocated and published prior to the start of each month. The Regulatory Authorities consider this should give participants a significant degree of certainty. The actual proportion of this sum which is earned by Generators will of course be dependent on their performance in the month. The remaining 30% of the total sum will remain uncertain until the end of the month, with this amount reflecting the actual value of capacity in each period. In seeking to strike a balance in the allocations the Regulatory Authorities have therefore considered the Objectives (including the Objective for the provision of short-term signals – the reason for the use of the Ex-Post element) and the comments from respondents. The Regulatory Authorities do not consider it necessary to write the allocations within the Trading and Settlement Code since it is not the intention for these allocations to be amended without good reason. However should such a reason arise it would seem arbitrary to predetermine the extent to which the allocations should be capable of being changed in the event that the signals provided prove to be undesirable. If circumstances arise which require a change then such a change should be capable of being implemented so as to correct whatever "error" has been identified, rather than being artificially constrained.

Bord Gais	The key area for Generators in the Capacity Payment Mechanism (CPM) is the proposed Fixed, Ex-Ante and Ex-Post Split of 30%, 40% and 30%, respectively; • In the paper issued by the joint Regulatory Authorities, entitled 'Capacity Payment Mechanism and Reserve Charging High Level Decision Paper', issued in June 2005, the Regulatory Authorities stipulated that their intention was to develop a fixed revenue CPM which would provide a degree of financial certainty to generators under the new market arrangements and a stable year-to-year pattern of capacity payments. • In the paper titled 'The Capacity Payment Mechanism and Associated Input Parameters', issued in July 2006, the Regulatory Authorities stated that a longer-term signal (for investment decisions) 'could be delivered by setting the annual revenue amount in a mechanistic and predictable manner, such that potential investors could make their own longer-term projections of revenue'. • It appears therefore that the Regulatory Authorities place a heavy reliance on the CPM to provide potential investors with incentives to build much needed generation plant for the system. The CPM was however also designed to incorporate incentives for short-term availability. The level of volatility in the current proposal will not allow investors to make longer-term projections of revenue with enough certainty. • The current fixed component of the CPM will provide a fixed known payment of only 30% of the total capacity payment amount in exchange for availability. New entrants require a level of certainty in payments to cover capital investment. Because of the growth in the market and the age portfolio of the current SEM plant, clear incentives should be made for new plant to be built. This could be better illustrated by increasing the fixed portion of the CPM. Maximizing the Ex-Post component would appear to suit a portfolio generator such as ESB PG. For a single site generator, new entrant IPP, this poses a risk in terms of capacity contribution. A single site IPP generator is more exposed to forced outages. If a single plant falls over due to a forced outage, overall average capacity revenue accruing to the generator would be significantly reduced while a portfolio generator would have more leverage to manage a similar situation. Maximizing the Ex-Ante (Variable) or Fixed components would provide a less risky payment stream for new build generators who would be expected to be available as much as possible.	The Regulatory Authorities consider allocating 70% of the CPM monies prior to the period in which they fall does provide the degree of certainty referred to (see above) while allowing for the retention of an element designed to provide short-term signals so as to meet immediate needs for capacity. While the Fixed component constitutes 30% as quoted in the response, a further 40% is known through the Variable (ex-ante) element ahead of time. Furthermore the mechanistic way in which the overall annual sum is determined should provide investors (existing and new) with the ability to undertake forecasts of future annual sums. The Regulatory Authorities do not agree that allocating more into the Fixed component would reduce the loss in revenue caused by a forced outage – a forced outage would mean that a Generator would not receive any CPM payments – fixed, variable or ex-post – for the period of the outage. This is consistent with the treatment a Generator would receive were it to suffer a forced outage in an energy only market. The Regulatory Authorities do not consider this to be sufficient to warrant a change in the allocations.

Bord Gais	• The Ex-Post payment however is based on an analysis of what happens in real-time. A single site generator will be able to provide little response to a sudden unexpected loss of generation availability to the market. Also, a sudden event for a single site generator which makes it unavailable may provide an incentive for a portfolio generator to reduce availability further in an effort to increase the monthly ratio of payment for that half hour(s) that will be paid to the total portfolio. The single-site generators have no control over the Ex-Post payments whatsoever. Therefore, the Ex-Post element should not be as high as 30% - and ideally should be as low as possible. In conclusion, the CPM should encourage all plant to be available at all times and in particular when the system requires the capacity most. However, in order to incentivise new investment in generation plant, the CPM should: (a) Be seen to be equitable to all generators, whether stand-alone plant or part of a portfolio. (b) Be certain enough to reduce risk costs for the market overall. The large Ex-Post portion does not lend itself to these requirements. An IPP generator should not be of the perception that they may be disproportionately penalised because of a technical fault (which may produce a negative response action from others), resulting in a significant loss of capital contributions. For this reason, we believe there should be a significant reduction in the Ex-Post portion of the CPM with the reduction amount being added to the fixed element.	In the event of a sudden, unexpected loss of generation to the market the Regulatory Authorities consider a signal to the market indicating that the value of capacity has increased to be an essential feature of the CPM design. The purpose of the signal is to provide an incentive to Generators to make additional capacity available so as to ensure capacity adequacy. This incentive applies equally to all Generators whether single site or large portfolio. To infer that capacity has the same value regardless of the supply/demand balance would ignore basic market economics. The Regulatory Authorities are therefore of the view that the CPM should recognise that the value of capacity changes with the margin and that the ex-post element provides the most accurate valuation (recognising the limitations of the LOLP = 1/0 argument noted earlier). The Regulatory Authorities also note that it is possible for a portfolio Generator to exacerbate the margin impact by withdrawing availability though they also note that the Generator would face significant risks in attempting to do so (see earlier). Nonetheless given the potential risk the Market Monitoring function has been tasked with implementing mechanisms to identify such behaviour. If a technical fault were to occur as described and the impact on the margin was to reduce an already small margin to a very small margin, then the Regulatory Authorities consider that the market should send a signal that indicates the value of capacity has risen significantly in order to illicit a response to address the problem. This is not a disproportionate penalty as suggested but rather a proportional signal based on the impact on the margin of the forced unavailability. If the forced outage occurs at a time of a large margin the impact will likely be negligible – rightly so since there will be plenty of spare capacity to cover the shortfall. .

ESB Int.	In view of the ongoing uncertainty about the LOLP determination, which impacts the volatility of the CPM, ESBI continues to favour a largely fixed ex ante payment. Our preferred allocation would be: fixed 50%, variable 25%, ex post 25%. A topic of concern to ESBI which is raised but not answered in the paper, and does not appear to be covered in the TSO's generator outage planning paper either, is that of generator outage scheduling and the CPM. At present there are no indications from the RAs on how they propose to compensate generators in the event of scheduled outages agreed with the relevant TSO being re-scheduled from a low-value Capacity Period to a high-value period, for example due to another generator over-running their scheduled outage. ESBI assumes that the generator which is re-scheduled would be made whole for any reduction in CPM revenues and would appreciate some details on how this will be covered in the market arrangements.	See earlier comments.
NIE	The proposal to reduce the extent of the volatility caused by ex-post re-allocation of payments does not solve the problem and it will continue to provide little incentive for a generator to respond given that the reward will be intangible at the time any decision by a generator is to be made. Similarly, the mismatch of treatment under the CPM of generation and demand means generators will not be able to secure a natural hedge with a supplier for what could be a volatile revenue stream. Notwithstanding our objection in principle, it is difficult to provide comment on the allocation in the absence of a detailed description and analysis of the precise design of the overall CPM package. However, NIE suggests that the best way to overcome the deficiencies described above (in the absence of setting the ex-post allocation to zero) is to minimise the allocation to the ex-post element to something of the order of 5%-10%. This would also minimise any distortion caused by low "relative" LoLPs (as discussed in the last paragraph of section 2.3 above). The consultation paper states that the RAs propose the 30:40:30 allocation for 2007 only. This indicates the allocation may be modified for 2008 which creates further uncertainty for any potential new entrant. The need for stability has been recognised as a key requirement and some framework is needed to describe the circumstances that would cause a revision to the allocation.	With the publication of this Decision document and that relating to the LOLP consultation, participants should now have all the information they require regarding the operation of the CPM. The LOLP consultation is considering the "low LOLP" issue and so it will not be considered here. However regarding the general point about the size of the ex-post element, the Regulatory Authorities have stated previously that the incorporation of the ex-post element into the CPM design is an essential feature. In order for the ex-post element to provide a signal to participants it needs to be of an appropriate size and should not be minimised as the respondent suggests. In determining the relative allocations between the three elements the Regulatory Authorities have balanced the objectives and have settled on the 30:40:30 allocation as providing the best match with those objectives. Whilst the Regulatory Authorities are of the view that this is the correct balance, experience of the operation of the market may indicate the need for a change to the allocation. It is for this reason that the Regulatory Authorities have stipulated that the allocation will apply from 2007. As has been stated previously, it is not the intention of the Regulatory Authorities to change this allocation without good cause.

VPE	VPE consider the LOLP components in the capacity mechanism to act as a disincentive to investment in new generation capacity as they result in volatility that cannot be hedged. The variable capacity payments proportion is less volatile than the ex-post capacity payment. VPE do not accept that a significant proportion of ex-post capacity payments will ensure that generators respond to on-the-day operational margins because the relative LOLP in the CPM significantly distorts any clear signal from a capacity shortage on a given day. On this basis we suggest that the proportions should be: Fixed capacity payments proportion 0.7 Variable capacity payment proportion 0.2 Ex-post capacity payments proportion 0.1 VPE contend that the above proportions will significantly reduce the cost of capital for new generators entering the market and reduce the requirement for the regulatory authorities to have “fire brigade” mechanisms for ensuring security of supply because investors have not sufficient confidence in the revenue streams from the SEM.	In establishing the relative allocations of the Fixed, Variable and Ex-Post elements the Regulatory Authorities took cognisance of the comments from respondents to the consultation (and previous consultations) and in particular noted the concerns regarding the uncertainty in the actual ex-post values given the fixed allocation. Establishing a price which seeks to value capacity more at times when it is required is a reasonable aim for the CPM given the various Objectives it is designed to meet. Furthermore in the absence of such a pricing mechanism only the energy market (SP) would remain as a financial incentive on generators to respond to plant shortages and the Regulatory Authorities are of the view that both the energy and capacity markets should be capable of sending out shortage signals. Having said this the Regulatory Authorities note the uncertainty in final prices due to the fixed allocation and the possibility that a signal of shortage which occurs at the start of a month could be undermined by subsequent shortages in the month. As a consequence of these factors and others outlined in previous responses, the Regulatory Authorities chose to fix the allocation of 70% of the sum of money prior to the start of each month to provide a high degree of certainty. The Regulatory Authorities could have chosen to make this a larger portion but considered that the consequent reduction of the Ex-Post element would undermine the effect of the signal provided through the Ex-Post element. It is recognised that this allocation requires a judgement to be made and the Regulatory Authorities, having considered all of the various factors, responses and Objectives of the CPM, have determined the allocation of 30:40:30 (Fixed, Variable, Ex-Post) to provide the best solution. Clearly the effect of this allocation will be monitored carefully by the Regulatory Authorities and if a major anomaly is identified it may become necessary for the allocation to be revised in subsequent years, however it is not the intention of the Regulatory Authorities to make any change without good reason and without having given the implications careful consideration.

	Eligible Availability for Energy Limited/Pumped Storage Units	
Synergen	Synergen has previously recognised the circular nature of the regime for Energy limited and Pumped Storage plant within the T&SC V1.0. However, the single snapshot approach envisaged may create perverse outcomes as an assessment on convergence (or otherwise) of an iterative algebraic approach has not been provided by the RAs and therefore its dismissal seems premature. Synergen would welcome the opportunity to review the RAs' analysis of this matter. However, Synergen notes that the need for such iteration is reduced (if not entirely removed) if the fixed element of the CPM is increased as per Section 8 of this paper.	Discussions with the TSOs have confirmed that the quantity of capacity expected to need to be scheduled in this manner is low given that such plant are highly likely to be scheduled by the EPUS run for the majority of their availability. Given this and the complexities of establishing more iterations to converge on a more optimal solution, the Regulatory Authorities are content with the proposal to limit the number of iterations in the way described.
Bord Gais	It should be made clearer that energy limited plant availabilities assumed from an initial despatch run also contribute to the market demand against which the margin calculation is made;	The margin calculation is made against a forecast of demand in the case of the ex-ante margin (s description of the methodology for which is included in this document), and the metered production of generating units in the case of the ex-post margin. The contribution to demand from energy limited plant (specifically pumped storage pumping) is accounted for accordingly.

VPE	The importance of pumped storage and energy limited plant to the dynamics of the SEM cannot be underestimated. VPE contend that they have significant market influence and supported the RAs decision to leave dispatch of pumped storage to the MCE (Market Clearing Engine) rather than based on market participant bids. VPE have requested information on the 24 October[1] from the MO on how the pumped storage and energy limited plant algorithms will work in the MCE but have not received a response as yet. Similarly VPE consider these plants as being potential influential in the CPM prices but it is very difficult to understand this dynamic without understanding how these plants will be dispatched. Given that their energy, and thus available capacity, is limited, then the dispatch process defines when their capacity is available to the market. The paper considers the "spare capacity" of the units. Why is it not the available capacity regardless of whether the unit is running or not? VPE contend that energy limited and pumped storage plant are very valuable assets on the Irish electricity system and that their capacity should be utilised by the MCE to minimise costs across the system. It would be damaging for the consumer and other market participants if the pumped storage and energy limited plants were manipulated to maximise their proportion of the capacity payments. They should however get paid a reasonable capacity payment, and in the case of pumped storage should also pay a reasonable capacity cost at times of pumping. VPE would welcome further clarification on the dispatch of energy limited and pumped storage plant and further analysis on how this interacts with the CPM. 1. Email to Jonathon O'Sulivan, copied to MO log for all market participants.	The Regulatory Authorities note the point regarding the despatch algorithm and also note that they asked interested parties to submit comments and questions regarding EPUS for consideration by the SEMIT team. A presentation on this questionnaire was delivered to the RLG in February and the written responses will be issued in due course. The Eligible Availability of such units does constitute all of their availability rather than just the "spare capacity" as indicated. The reason for referring to the spare capacity is that the optimisation process described in the rules only relates to the spare capacity – the remainder already having been scheduled in EPUS and accounted for in values of Eligible Availability for the relevant Trading Periods.

	Other Comments	
NIE	NIE has stated previously that it considers that the total payment should not be the same in each year but should rise or fall with the margin. The present proposal seems likely to damp the price signal by too much. Suppose the equilibrium margin is 20%. A zero margin would only raise the capacity price per unit by 20%, which is far too modest a response to a critical situation when LoLE is probably over 300 hours. The payment would be better as the calculated equilibrium sum divided by the ratio of the actual capacity/peak demand ratio to that at equilibrium raised to some power. So, for example, in the 20% example where the power is 1, the capacity price per unit would be raised by 44% if there was a zero margin. Using the ratio squared would raise it by 73% and cubing it would more than double the unit price. The RAs have not commented on this concern. However, the one issue that has not yet been properly or rationally considered is the treatment of capacity on external interconnectors and the eligibility of such capacity to receive capacity payments. It is clear that in an ex-ante evaluation, the exclusion of the capacity could materially change the margin and as a result the relative LoLP across a capacity period. The treatment of the security provided by the capacity must also carry through on a consistent basis to any ex-post calculation and in NIE's opinion, any unused capacity is still contributing to ensuring security of supply for customers. This issue needs to be addressed urgently before any final decisions can be made on the overall CPM structure.	The objective of the approach adopted (i.e. the use of a Capacity Requirement and a BNE Price) is to provide funds to reward the required level of capacity to the commensurate amount given reference to an energy only market. Actual payments to Generators will, in this way, vary with the margin as suggested – if the amount of installed capacity is greater than that required to meet the identified security standard the per unit payment will decrease. In contracts if the margin falls below that required to meet the adequacy standard the per unit payment will rise. Other options are of course possible such as that proposed or by applying some other form of scaling factor but the Regulatory Authorities are not convinced of the efficacy of such options. Furthermore a mechanism which increased the amo0unt of money allocated to the CPM by means of a scaling factor based on margin would not meet the CPM Objective of ensuring Generators are not paid twice. The arguments regarding the payments to Interconnectors have been addressed previously[13]. On a long-term ex-ante basis (such as in the derivation of the Capacity Requirement or the calculation of the ex-ante margin, it is reasonable to consider the capacity of the Interconnector to be fully available since Interconnector Users could, if they wished, make such capacity available at the Day Ahead stage. However if such users decide not to offer prices for their full capacity into the market at the day ahead stage then their capacity on the day cannot be guaranteed (it being a function of prices and the availability of capacity in an adjoining market) and their contribution to security of supply has to be treated in such a way as to reflect this.

13 http://www.allislandproject.org/2006/AIP-SEM-98-06.pdf