SEM committee

Integrated Single Electricity Market
(I-SEM)

Capacity Remuneration Mechanism
Parameters and Auction Timings

Decision Paper

SEM-17-022

10 April 2017

EXECUTIVE SUMMARY

Introduction

This decision paper adds to the complement of CRM detailed design decision papers published to date and represents the decisions associated with:

- The CRM parameters (SEM-16-073) which closed on 21st December 2016; and
- Contains our decision on the definition of the transitional period, which was consulted on in Section 4 of the consultation paper on the Capacity Market Code (SEM-17-004), which closed on 24 February 2017. The extension of the transitional period to include Capacity Year (CY) 2021/22, which follows from the decision to delay the go-live of the I-SEM to 23 May 2018 has implications for some of the parameter values, which is why we are publishing this decision alongside the parameters decisions.

The decisions within this paper follow on from the associated consultations. Feedback from stakeholders, including responses and the stakeholder workshop held on 2 March 2017, has been considered in arriving at the decisions within this paper.

Overview of CRM Parameters

The I-SEM CRM Detailed Design has been developed through a series of detailed design papers. These I-SEM Detailed Design papers have established a number of CRM related parameters which need to have values set in order for the I-SEM CRM to become operational. Some of these parameters relate to the general operation of the I-SEM CRM, whilst others relate specifically to the first Transitional Auction, scheduled to take place in December 2017.

In addition, the detailed implementation of the policies into the Capacity Market Code (CMC) has created a small number of additional lower level parameters whose values also need to be set for the I-SEM CRM to become operational. The Capacity Market Code has been developed through the TSOs Rules Working Group process involving industry input and feedback. Following this process the Regulatory Authorities published a consultation on this Capacity Market Code (SEM-17-004/004a) during January 2017, with responses received by 24 February 2017.

The purpose of the CRM parameters consultation has been to establish the values for the CRM parameters which are required to support the first Transitional Auction and/or to support I-SEM CRM go-live. Some of these parameter values will be captured in the CMC. Others will be captured within the Trading and Settlement Code (TSC) since Capacity Market settlement is governed by the TSC, and some of these parameters are regulatory parameters which the RAs/SEM Committee will apply in regulating auction bids, but which will be set outside the CMC and TSC.

Summary of Transitional Auction Timings

At a high level, the SEM Committee has decided to have a single auction with a single Qualification process for the approximately 16-month period from go-live (anticipated 23 May 2018) to 30 September 2019. The SEM Committee has also decided that:

- There will be a single Qualification process. Capacity providers must Qualify for both the 4-month period from go-live to the end of CY2017/18 and CY2018/19, or opt out of both periods;
- The RAs will define a single set of Auction Parameters, appropriate for CY2018/19;
- Bidders will submit a single bid price for both periods; and

- There will be the same clearing price for both CYs, and the same volume of Reliability Options will be awarded to the same bidders in CY2017/18 (a 4-month Reliability Option) and CY2018/19 (a 12-month Reliability Option).

The SEM Committee has decided to make CY2021/22 a transitional year, so:

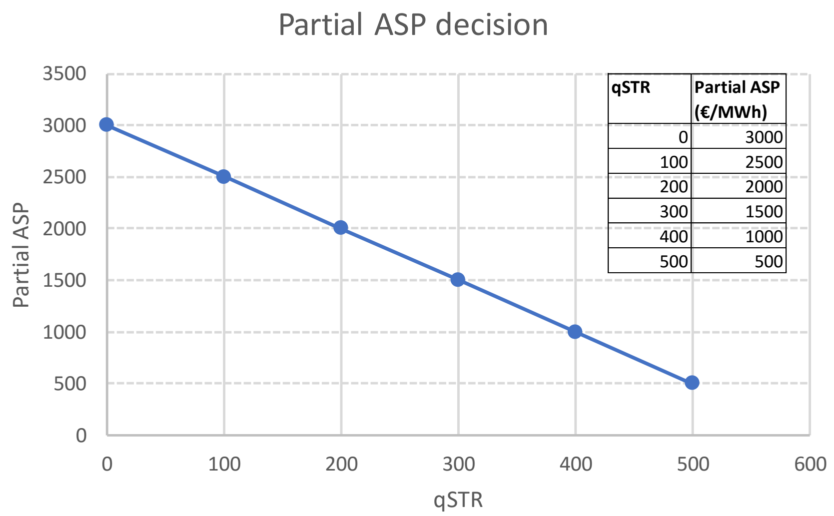
- The first T-4 auction will be in respect of CY2022/23, and would be held approximately 4 years in advance of the start of the Capacity Year;
- We will not hold a T-4 auction for CY2021/22 but will procure all capacity for CY2021/22 through a transitional T-1 auction; and
- The Capacity Requirement for all transitional years 2018/19, 2019/20, 2020/21 and 2021/22 will be based upon the demand forecast for 2021/22.

The first Transitional Auction is planned to take place on 15th December 2017, and a more detailed timetable for the auction process is set out in this document.

Administrative Scarcity Pricing

In CRM Decision 1 (SEM-15-103), the SEM Committee decided that Administrative Scarcity Pricing (ASP) will be introduced into the energy imbalance price, and that ASP will apply when there is insufficient available capacity to cover the combination of demand and the target level of operating reserve. The BM Imbalance Price in any such Settlement Period will be the higher of the simplified piece-wise linear function, or the BM Imbalance Price as otherwise determined by the I-SEM ETA Markets Decision Paper (SEM-15-065. CRM Decision 2 (SEM-16-022) stated that the value of Full ASP (to apply when load shedding has occurred) will be set at the Euphemia day ahead price cap of €3,000/MWh for a transitional period, after which it will be based on VoLL. In the CRM Parameters consultation, we consulted on the value of the Partial ASP function, which applies when there is insufficient capacity to cover the target operating reserve but load shedding has not yet occurred. **The SEM Committee has decided to implement Option 1** of the options presented in the consultation. As illustrated in Figure 1 below **Partial ASP will start at €500/MWh when short term reserve is 500MW, rising in a straight-line manner to the Full ASP value of €3,000/MWh when there is no short term reserve left**.

Figure 1: Partial ASP decision



qSTR	Partial ASP (€/MWh)
0	3000
100	2500
200	2000
300	1500
400	1000
500	500

Cost recovery and charging

In CRM Decision 1 (SEM-15-103) the SEM Committee decided that CRM charges to Suppliers will be recovered as a fixed €/MWh charge across demand in a pre-defined set of half hours (called the Supplier Charging Base) that are judged to be those most likely to have high LoLP values. In the CRM Parameters consultation, we consulted on which half hours they should be. The SEM Committee has now decided on **Option 3: A broader based Supplier Charge, with Supplier charges focused on a broader day-time period from 7am to 11pm in all quarters.**

Reliability Option parameters

In the CRM Parameters consultation (SEM-16-073) we sought consultation feedback on the following Reliability Option parameters:

- The DSU floor price. In CRM Decision 1 (SEM-15-103) stated that to facilitate DSU participation the SEM Committee plans to set a floor price to the Reliability Option Strike Price, the "DSU Floor Price". **The SEM Committee has now decided to set the DSU floor price at €500/MW**;
- The Billing Period Stop-Loss Limit. In CRM Decision 1 (SEM-15-103), the SEM Committee decided that Stop-Loss Limits would apply. These Stop-Loss Limits cap a capacity provider's exposure to uncovered difference payments. In CRM Decision 2 (SEM-16-022) the SEM Committee further decided that an Annual and a per Billing Period Stop-Loss Limit will be used[1], and that the Annual Stop-Loss Limit will be set to 1.5 x the Annual Reliability Option Fee for a capacity provider. The SEM Committee stated that it was minded to set the Billing Period Stop-Loss Limit to 0.5 x the Annual Stop-Loss Limit (i.e. 0.75 x the Annual Reliability Option fee) but deferred the final decision on the Billing Period Stop Loss Limit. **The SEM Committee now confirms its decision to set the Billing Period Stop-Loss limit at 50% of the Annual Stop Loss Limit**.
- Carbon Intensity Factors; and
- Transport Adders.

As we discussed in SEM-16-073, the Carbon Intensity Factors and the Transport Adders will depend in part on the fuel and carbon indices chosen to set the Reliability Option Strike Price. In CRM Decision 3 (SEM-16-039), the SEM Committee decided that the CRM Delivery Body will propose indices for approval by the RAs. Evaluation is ongoing, and it is expected that the SEM Committee will make a decision on the fuel and carbon indices, the Carbon Intensity Factors and the Transport Adders in due course, taking into account feedback received during the CRM Parameters consultation. These fuel and carbon indices, Carbon Intensity Factors and Transport Adders will then be published in the Initial Auction Information pack to be issued in July.

New Build, Termination Fees and Performance Bonds

The SEM Committee has taken the following decisions with regard to new capacity, Termination Fees and Performance Bonds:

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[1] There are benefits to aligning the stop-loss limit with the billing period used for energy settlement. This will increase the possibilities for netting off payments and charges in settlement and will help to manage the credit risk from participants and improve the efficiency of the market. In consequence, the SEM Committee decided to use a stop-loss limit aligned with the settlement billing period, rather than use a monthly stop-loss limit.

- The New Capacity Investment Rate Threshold (NCIRT) is the amount that a new investor must invest per kW of capacity to qualify for a multi-year Reliability Option. Following consultation, **we have decided to set the NCIRT at 40% of the gross BNE investment cost**, i.e. 10% less than the 50% proposed in the consultation document. For the first transitional auction, this will be €300/de-rated kW.
- Termination Fees for new (uncommissioned) capacity: **The SEM Committee confirms its proposals that all uncommissioned capacity (including DSUs), will be subject to the following Termination Fee schedule as proposed in SEM-16-073**:

    - Termination at any time after the auction but more than 13 months before the start of the Capacity Year: €10/kW. A T-1 auction may occur between 2 and 13 months prior to the start of the Capacity Year;
    - Termination between 13 months before the start of the Capacity Year and the start of the Capacity Year: €30/kW;
    - Termination after the start of the Capacity Year: €40/kW

- **Existing (commissioned) capacity shall not be subject to Termination Fees**;
- Performance bonds: **All capacity is required to post a Performance Bond to cover 100% of its Termination Fee exposure.**

Auction Price Cap and Net CONE

In CRM Decision 3 (SEM-16-039), the SEM Committee decided on a number of auction bid control parameters, including the Auction Price Cap (APC), which is the maximum price qualified bidders may bid their qualified volume at, and is therefore the maximum price that the auction can clear at. In addition, the Existing Capacity Price Cap (ECPC) applies to existing generators and interconnectors, unless they obtain a Unit Specific Price Cap (USPC). In practice, this means that the APC is only likely to be binding on new capacity, and existing DSUs, which are not bound by the ECPC.

In the CRM Parameters consultation, the SEM Committee stated that it proposed to set the APC at 1.5 x Net CONE, which is at the lower end of the international range, given the current excess of capacity over the Capacity Requirement. The SEM Committee also consulted on a number of changes to the SEM Best New Entrant calculations to reflect the move from the SEM to the I-SEM.

Following consultation, the SEM Committee has decided to:

- Adopt the proposed changes to the Net CONE calculation set out in the consultation document (SEM-16-073). The indicative value for Net CONE is €78.82/de-rated kW/year;
- Set the Auction Price Cap for the first transitional auction at 1.5 x Net CONE. The indicative value for the Auction Price Cap is €118.23/de-rated kW/year;
- Finalise the Net CONE (and hence APC and ECPC) for the first transitional auction, taking account of changes to the BNE reference plant de-rating factor and the latest inflation value, for approval by the June SEM Committee meeting. The final value will be included in the Initial Auction Information Pack in early July 2017; and
- Review the key assumptions in setting Net CONE before the first T-4 auction, which will be for capacity delivery in CY2022/23.

Existing Capacity Price Cap, Net Going Forward Costs and Unit Specific Price Caps

In addition to the Auction Price Cap, in CRM Decision 3 (SEM-16-039), the SEM Committee decided to introduce the following bid limits which should apply to existing generators:

- A Uniform (i.e. non-technology specific) Price-taker Offer Cap. This parameter has been termed the Existing Capacity Price Cap (ECPC) in the Capacity Market Code drafting. All existing generators and interconnectors will be required to bid their full qualified volume into the transitional auctions and the T-4 auctions at a price no higher than the ECPC (specified in €/kW or £/kW), unless they apply for higher USPCs as set out below, or submit an Opt-Out Notification on the grounds that they are going to close before the end of the relevant Capacity Year (subject to Grid Code provisions) or be mothballed, or on a planned outage;
- Right to apply for a higher USPC: Where an existing generation or interconnector is able to evidence the fact that it has higher unavoidable Net Going Forward Costs (NGFCs) than the Existing Capacity Price Cap, it will be able to apply to be allowed to submit a higher Unit Specific Price Cap– up to the level of the unit's individual Net Going Forward Costs. The SEM Committee may then set a USPC specific to that unit for that auction, at a higher level than the ECPC, commensurate with its view of the unit's NGFCs.

In the CRM Parameters consultation, the SEM Committee set out its proposals to calculate the NGFC for an individual unit as:

NGFC = Max [(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets),0] + Expected Reliability Option difference payments

The SEM Committee also proposed to set the ECPC at 0.5 x Net CONE, a price which is expected to be above the NGFC of most capacity required to meet the Capacity Requirement.

There was strong push back from the industry on the SEM Committee's proposed NGFC formula and proposals to set the ECPC at 0.5 x Net CONE as in their view it would not allow existing generators to recover their sunk costs (including depreciation, interest, return of equity).

Stakeholders also noted that there was significant uncertainty around the calculation of NGFC, particular around key inputs, and argued that there was insufficient allowance for refurbishment/upgrade investments which fall short of the threshold to qualify as new (i.e. are below the NCIRT), since there was no allowance for these investments in the NGFC formula.

The SEM Committee confirms its decision to set the ECPC at 0.5 x Net CONE and not to include any allowance for sunk costs in the NGFC formula since. Given the current excess of capacity over the Capacity Requirement, in a competitive market, where bidders are not able to exercise market power, we would not expect them to include sunk costs in their bids.

The SEM Committee have decided to make two key changes to the NGFC and the setting of USPCs as a result of the feedback received. The SEM Committee will allow:

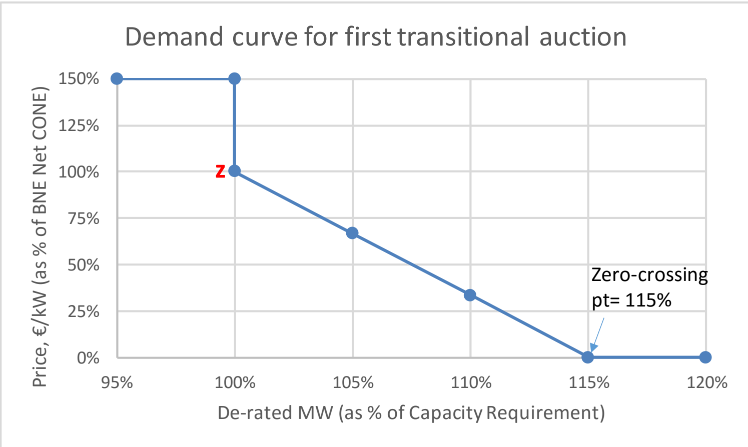
- **Any existing generator making refurbishment/upgrade investment (which is less than the NCIRT) to include a proportion of that unavoidable investment in a USPC;**
- **For 10% NGFC estimation uncertainty in setting USPCs**.

Auction Demand Curve

The SEM Committee has decided to set the demand curve for the first transitional auction as follows:

- The curve will be horizontal at the Auction Price Cap (150% of the BNE Net CONE) between 0MW and 100% of the Capacity Requirement;
- The demand curve will be vertical at 100% of the Capacity Requirement between a price of 150% of BNE Net CONE and 100% of BNE Net CONE (point Z on the diagram below);
- The demand curve will be a straight-line slope between point Z and a zero-crossing point at 115% of the Capacity Requirement.

Figure 2: Demand curve decision



This decision is expressed in terms of percentages of the Capacity Requirement, rather than de-rated MW, since the Capacity Requirement remains to be finalised. The indicative Capacity Requirement presented in SEM-16-073 will be updated to reflect a number of updates / decisions including:

- The revised TSOs demand forecast scenarios set out in the 2017 Generation Capacity Statement (GCS)[2];
- The SEM Committee's decision set out in SEM-16-082, not to add the reserve requirement to the Capacity Requirement initially, which removes approximately 450MW from the Capacity Requirement; and
- The decision to make CY2021/22 a transitional year, so that the Capacity Requirement for the first transitional auction will be based on the CY2021/22.

The Capacity Requirement will depend in part on final de-rating assumptions (including the interconnector de-ratings). Once the final de-rating factors are calculated and approved by the SEM Committee the provisional demand curve will be published in de-rated MW in the Initial Auction Information Pack (in early July 2017). This demand curve will then be adjusted for capacity which is not going to close, but has exercised its discretion not to bid into the auction. The final demand curve will then be published in de-rated MW terms in the Final Auction Information Pack.

[2] Previous numbers were based on the 2016 Generation Capacity Statement

Locational parameters

Following the decision in the CRM Locational Issues decision paper (SEM-16-081) to recognise locational constraints in the CRM auction, and to represent them as nested capacity zones there is the need to define:

- The actual constrained zones to be used in the first transitional auction, including their geographic boundaries; and
- Locational capacity requirements parameters for those zones.

In the CRM Parameters consultation paper (SEM-16-073), we stated a view that the local capacity requirements for the constrained zones should be represented by simply specifying a minimum de-rated MW requirement for each zone, rather than introducing sloping local (zonal) demand curves.

Respondents agreed with that approach, and the SEM Committee confirms that intention. Therefore, the key locational parameters for the first transitional auction will be:

- The zones (how many, how each is defined geographically)[3]; and
- The minimum MW of Reliability Option to be awarded in each zone.

The SEM Committee has asked the TSOs to develop a methodology for defining the zones and for defining the minimum MWs in each zone. The SEM Committee plans to consult on that methodology in mid-April 2017, and make its decision on that methodology in June in advance of the Initial Auction Information Pack. The TSOs, as the CRM Delivery Body will then publish the actual zones in the Initial Auction Information Pack in early July, following approval of their analysis by the SEM Committee. However, the minimum MW required in each zone will be withheld until after potential capacity providers have submitted an application for a USPC or an opt out notification and the final demand curve has been determined.

System Constraints

The SEM Committee notes that some market participants have argued that there may be a specific issue with regard to plant which is both selected in the capacity mechanism to meet local capacity requirements and that are constrained-on in the Balancing Market to meet system constraints to a very material degree, or only runs when constrained-on.

In this regard the SEM Committee recognises that this issue needs to be considered further and there may be a need to put in place targeted contracting mechanisms to address local security of supply requirements which may emerge after the auction. This possible need for contracting flexibility was recognised in the SEM-16-081 (CRM Locational Issues Decision paper) and SEM-14-108 (DS3 System Services Procurement Design and Emerging Thinking Decision paper). The SEM Committee, along with the TSOs, will continue to consider the need for an appropriate framework for any such mechanism. These considerations will take account of the overall energy, capacity and system services market framework and relevant Grid Code requirements. Further information will be provided on this over the coming months.

[3] in much of the discussion so far, the working assumption is that there will be two constrained zones, Northern Ireland and the Dublin area, but this is only an assumption, and the boundaries of the Dublin area have not been defined

Other issues

The Capacity Requirement and De-Rating Methodology Decision (SEM-16-082) stated that DSUs will be de-rated on the basis of the System-Wide De-rating Curve, but will be permitted a negative tolerance (DECTOL) to qualify below this level. The SEM Committee have decided to set DECTOL equal to 100% for the first Transitional Auction.

The SEM Committee have decided to set the outage rates for the Interconnector Technology Class, based on historical data up to the end of 2016 as follows:

- Forced Outage Rate: 6.9%
- Scheduled Outage Rate: 3.7%

The SEM Committee have decided to set the External Market De-Rating Factor (EMDF) for Great Britain to 60% for the first Transitional Auction. An indicative value for the combined effect of these parameters on the de-rating of a 500MW interconnector is approximately 45%. This value is only an estimate and a value based on the actual de-rating curves for the interconnectors will be included in the initial Auction Information Pack, once the TSOs have completed work on generic de-rating curves.

Next Steps

The SEM Committee will consult on the TSOs' proposed methodology for identifying the constrained zones for the first transitional auction and the minimum MW required in each zone in mid-April, and publish the decision in early July.

The SEM Committee will publish the Capacity Market Code in early June.

The CRM Delivery Body will publish an Initial Auction Information Pack in July, at the start of Qualification. The Initial Auction Information Pack will set out a range of information that will help market participants to submit their Qualification information, to decide whether to submit USPC bids, and inform their auction bids. It will include some updates to parameters set out in this document as approved by the SEM Committee. A Final Auction Information Pack, is expected to be issued on 1st December 2017 The Final Auction Information Pack will also set out the final demand curve, updated for Qualification results, and publish the minimum MW required in each constrained zone.

Contents

1 INTRODUCTION

1.1 BACKGROUND

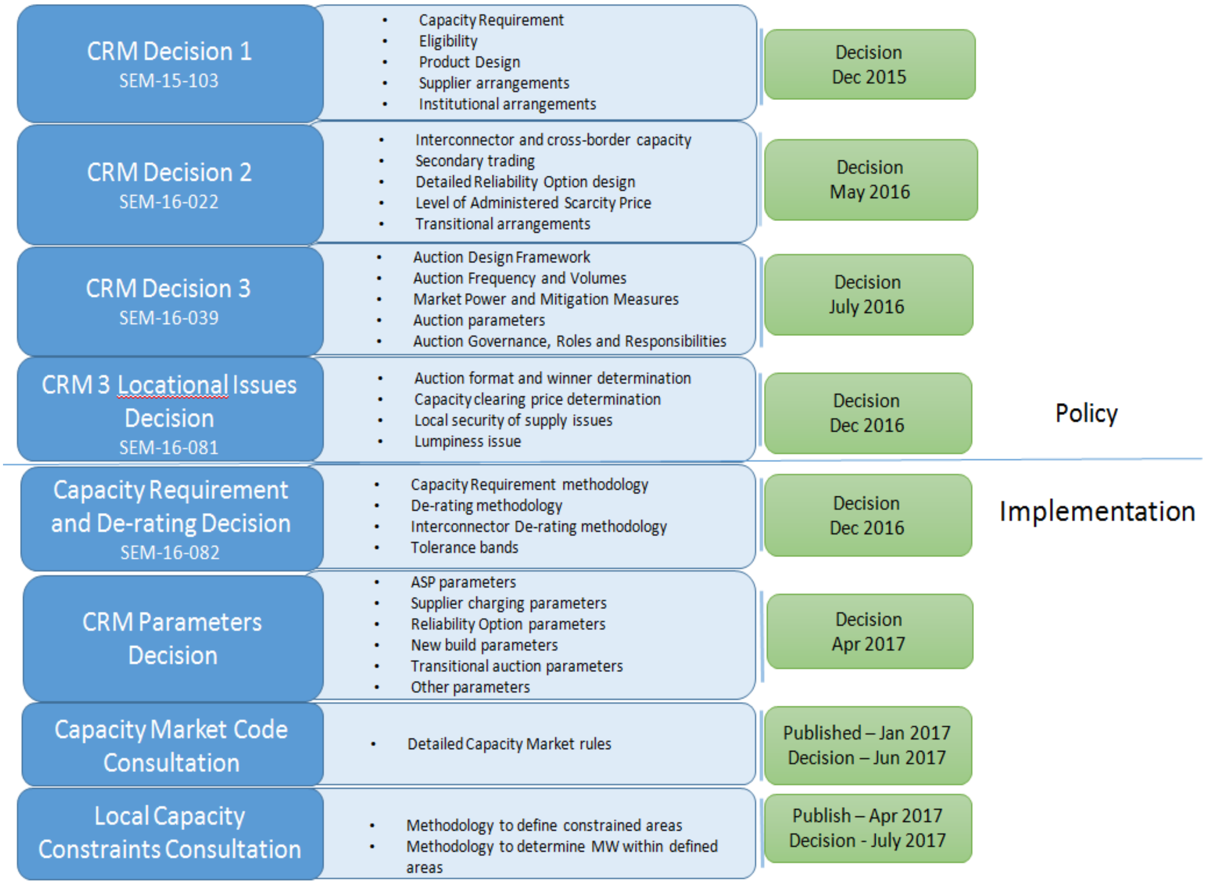
1.1.1 The I-SEM CRM Detailed Design has been developed through a series of consultation and decision papers. These I-SEM Detailed Design papers have established a number of CRM related parameters which need to have values set in order for the I-SEM CRM to become operational. Some of these parameters relate to the general operation of the I-SEM CRM, whilst others relate specifically to the first transitional auction.

1.1.2 In addition, the detailed implementation of the policies into the Capacity Market Code (CMC) has created a small number of additional lower level parameters whose values also need to be set for the I-SEM CRM to become operational. The Capacity Market Code has been developed through the TSOs Rules Working Group process involving industry input and feedback. Following this process the Regulatory Authorities published a consultation on this Capacity Market Code (SEM-17-004/004a) during January 2017, with responses received by 24 February 2017.

1.1.3 The purpose of the CRM parameters consultation has been to establish the values for the CRM parameters which are required to support the first Transitional Auction and/or to support I-SEM CRM go-live. The paper also sets out proposed values, which are expected to be included in the Auction Information Pack for the first Transitional Auction. Some of these parameter values will be captured in the CMC. Others will be captured within the Trading and Settlement Code (TSC) since Reliability Option settlement is governed by the TSC.

1.1.4 The overall detailed design and implementation process is illustrated in Figure 3 below.

Figure 3: Overview of CRM Development



1.1.5 Following the I-SEM stock-take and the decision to postpone the go-live of the I-SEM to May 2018 (see Stocktake Summary SEM-16-078a), the SEM Committee considered making some changes to the auction timetable, extending the transitional period to include the Capacity Year (CY) 2021/22.

1.1.6 These changes were consulted upon along with the Capacity Market Code draft in SEM-17-004. The SEM-17-004 consultation closed on 24 February 2017, and the SEM Committee has now reviewed the responses. The SEM Committee has decided to publish its decision on the transitional auction timings in this CRM Parameters document since the decision has implications for the setting of CRM parameters for the first transitional auction.

1.1.7 The first Transitional Auction is now planned to take place on 15th December 2017, and to cover capacity delivery over the period from go-live to the end of CY2018/19.

1.2 ABOUT THIS PAPER

1.2.1 This paper details the SEM Committee's decisions on specific parameters associated with the detailed design of the I-SEM Capacity Remuneration Mechanism (CRM). Included within this paper is a summary of the responses made to the consultation paper issued on 8 November

2016, SEM-16-073, together with the SEM Committee's response to the key points raised. Where relevant, next steps are also set out.

1.2.2 The introduction of the CRM will involve notifying the proposed mechanism to the European Commission (EC) in relation to State Aid, a process which will be led by the Department of Communications, Climate Action & Environment (DCCAE) and the Department for the Economy (DfE). This paper has been developed to be consistent with guidelines published by the EC in this respect; however, it is subject to the outcome of this notification process.

1.2.3 Some of the parameter values set out in this paper are not expected to change prior to publication of the Auction Information Pack and first capacity auction. For other parameters (e.g. demand curve for the first Transitional Auction), this document prescribes the methodology / process by which the final parameter values will be calculated. For instance, in the case of the demand curve, the calculation of the 2018/19 Capacity Requirement will be provided by the TSOs, and the demand curve will also need to be adjusted based upon Qualification results, so the final demand curve will not be published until early December 2017.

1.2.4 The structure of this paper is as follows:

- **Section 2: Transitional Auction timings** sets out our decision with respect to the timing of Transitional auctions, i.e. our decision in respect of the questions posed in Section 4 of the Capacity Market Code consultation (SEM-17-004). These decisions have consequences for the value of some of the key parameters in other sections;
- **Section 3: Administrative Scarcity Pricing Parameters** discusses the shape and slope of the ASP function;
- **Section 4: Cost Recovery and Charging** sets out the details of the Supplier Charging Base, i.e. the hours in which charges to Suppliers to recover capacity costs will be levied;
- **Section 5: Reliability Option Parameters** sets out the detail of the DSU Floor Price and the Billing Period Stop-loss Limit. Evaluation of the fuel and carbon indices to be used in the Strike Price calculation is ongoing, and the choice of indices will be published in the Initial Auction Information Pack in July, along with the consequential Carbon Intensity Factors and Transport Adders;
- **Section 6: Auction Parameters** sets out the approach to setting the values for the Auction Price Cap, Net Cost of New Entry (Net CONE), the Existing Capacity Price Cap (ECPC) and Unit Specific Price Caps (USPCs), Demand Curve Parameters and Locational Parameters. Some of these parameters will be revised following further input from the TSOs. The focus on this section is the value of the parameters for the first Transitional Auction. Parameters for subsequent auctions will be set (and as appropriate consulted upon) in advance of the relevant auction.
- **Section 7: New Build, Termination Fees and Performance Bonds** sets out the approach and indicative values for the New Capacity Investment Rate Threshold, schedule of Termination Fees and Performance Bonds;
- **Section 8: Other parameters** sets out the value for other parameters, or explains why the parameters are not relevant at this time.
- **Section 9: Next steps** sets out the key updates to parameters between now and go-live, as well as other next steps in CRM implementation.

1.2.5 Each section sets out a summary of the issues consulted upon, provides an overview of respondent's views, sets out the SEM Committee's response to the key points raised and then specifies the SEM Committee's decision on each matter (along with next steps, as relevant).

1.3 RESPONSES TO CONSULTATION

1.3.1 This paper includes a summary of the responses made to the CRM Parameters Consultation paper (SEM-16-073) which was published on 8 November 2016, and closed on 21 December 2016.

1.3.2 A total of 20 responses to the consultation were received. These were submitted from a wide range of interested parties including Generators, Suppliers, the Transmission System Operators and Industry Representative Groups. Of the 20 responses, one has been marked confidential, however a public version was provided. We note that most of the arguments raised in the confidential response were a subset of the points made in the non-confidential responses, and the SEM Committee has not relied on any evidence presented in the confidential response which is not available to all stakeholders. The 20 respondents are outlined below and copies can be obtained from the SEM Committee website.

- AES
- BGE
- Bord na Mona
- DRAI
- Eirgrid/SONI
- EAI
- Electric Ireland
- Energia
- ESB GWM
- Gaelectric
- Indaver
- IWEA
- Lumcloon Energy
- Moyle Interconnector
- Power NI
- Power NI PPB
- Rusal Aughinish
- SSE
- Tynagh
- Vayu

1.3.3 We note that we also received some feedback on CRM parameters contained within the CMC as part of responses to the consultation on the CMC (SEM-17-004/004a).

1.3.4 After reviewing the responses, we presented our emerging thinking on the CRM Parameters at a stakeholder workshop in Dundalk on 2 March 2017. We received further feedback at the workshop, and that feedback has also been taken into account in developing our final decision.

1.4 ASSESSMENT CRITERIA

1.4.1 The assessment criteria for the parameter values of the CRM are based on the same principles as those applied to the I-SEM High Level Design and as agreed with the Departments in the Next Steps Decision Paper published March 2013. We have developed detailed descriptions of these criteria to focus on issues that are relevant to procuring capacity and tailored to the detailed design elements of the Capacity Remuneration Mechanism.

1.4.2 These assessment criteria are set out below:

- **The Internal Electricity Market:** the market design should efficiently implement the EU Target Model and ensure efficient cross border trade.
- **Security of supply:** the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.
- **Competition**: the trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner.
- **Equity:** the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner.
- **Environmental:** while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.
- **Adaptive**: The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.
- **Stability:** the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.
- **Efficiency:** market design should, in so far as it is practical to do so, result in the most economic overall operation of the power system.
- **Practicality/Cost**: the cost of implementing and participating in the CRM should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.

1.4.3 Fundamental to the SEM Committee's consideration of the overall CRM design is the European Commission State Aid Guidelines. In this regard, , we have engaged with the Departments (DCCAE and DfE) and the European Commission as we have developed the capacity market design as ultimately EC approval is required for the CRM auctions to commence.

2 TRANSITIONAL AUCTION TIMINGS

2.1 INTRODUCTION

2.1.1 Following the I-SEM stock-take and the decision to postpone the go-live of the I-SEM to May 2018 (see Stocktake Summary SEM-16-078a), the SEM Committee considered making some changes to the auction timetable, extending the transitional period to include the Capacity Year (CY) 2021/22.

2.1.2 These changes were consulted upon along with the Capacity Market Code draft in SEM-17-004. The SEM-17-004 consultation closed on 24 February 2017, and the SEM Committee has now reviewed the responses. The SEM Committee has decided to publish its decision on the Transitional Auction timings in this CRM Parameters document since the decision has implications for the setting of CRM parameters for the first Transitional Auction.

2.2 CONSULTATION SUMMARY

2.2.1 SEM-17-004 set out the following SEM Committee proposals:

- **Transitional Auctions**: To hold a single capacity auction in December 2017 to cover the period from go-live to 30 September 2019, a period of just over 16 months; and
- **T-4 auctions**: To hold the first T-4 auction in August 2018, related to capacity delivery in CY 2022/23 (from 1 October 2022 to 30 September 2023).

2.2.2 As a result, SEM-17-004, proposed that CY2021/22 would be a transitional year.

2.2.3 SEM-17-004 also set out a number of consequences of the proposed changes:

- A single Qualification process. Capacity providers must Qualify for both the 4-month period from go-live to the end of CY2017/18 and CY2018/19, or opt out of both periods;
- A single set of Auction Parameters, appropriate for CY2018/19;
- Bidders submitting a single bid price for both periods; and
- The same clearing price for both CYs, and the same volume of Reliability Options being awarded to the same bidders in CY2017/18 (a 4-month Reliability Option) and CY2018/19 (a 12-month Reliability Option).

2.2.4 The proposed approach will result in the same option fee per month being payable to Capacity Providers in the 4 and a bit months of CY2017/18 as in the 12 months of CY2018/19- since Option Fees are structured as a flat €/kW or £/kW value across the year. As customers' consumption is lower in summer than winter, this is likely to result in slightly higher Supplier charges in the remainder of CY2017/18 than in CY2018/19, but the impact was not considered material.

2.2.5 The SEM Committee noted that one implication of extending the transition period to include CY2021/22 is that the Capacity Requirement for each of the transitional years CY2018/19 to CY2021/22 would be based on demand forecasts for CY2021/22, which means that the Capacity Requirement will be higher in each of CY2017/18 to CY2020/21 as a result. This follows the decision to base the Capacity Requirement for each of the transitional years on the demand forecast for the end of that period.

2.2.6 SEM-17-004 set out that based on these proposals, the indicative auction timetable for the first few auctions would be as follows:

- December 2017: Transitional Auction for CY2017/18 and CY2018/19;
- August /September 2018: T-4 Auction for CY2022/23; and
- March 2019: Transitional Auction for CY2019/20.

2.2.7 We would then expect to hold:

- Transitional auctions for each of the remaining transitional years on an annual basis in advance of the relevant CY. These may be consistent with T-1 auction timeframes for each CY, but in line with CRM Decision 3 (SEM-16-039), once lessons learnt from the first transitional auction have been appropriately reflected, the SEM Committee will consider further the possibility of holding subsequent transitional auctions in sequence at an earlier stage; and
- T-4 and T-1 auction for each subsequent year in line with the standard timeframes set out in the current CMC draft.

2.3 SUMMARY OF CONSULTATION RESPONSES

2.3.1 The majority of respondents broadly agreed with the approach set out in the consultation paper, in particular:

- That it was appropriate for the first transitional auction to be for the balance of CY 2017/18 and full CY2018/19;
- That the first T-4 Auction should now be in respect of delivery CY2022/23.

2.3.2 However, respondents also expressed a preference to have all subsequent transitional auctions (for CY 2019/20, CY 2020/21 and CY 2021/22) before the first T-4 Auction in order to provide greater certainty for participants.

2.3.3 Some respondents also expressed a number of other concerns, including that:

- The timetable for each auction should be clearly specified, providing sufficient certainty and time for participants to carry out their assessments and activities.
- The potential for running a T-1 transitional auction within two months of a capacity year leads to a very short-timeframe for a supplier to arrange hedging.
- The proposed timelines for the first transitional auction are very compressed.
- It is unclear how CMC accession can commence in advance of the licences becoming effective- the implication being that it would be necessary for the CMC accession to happen before the licence changes would become effective for the proposed auction timetable to be met.

2.3.4 The TSOs, who will be responsible for running the auction, did not agree with the idea of holding the transitional auctions in sequence before the first T-4 auction. Rather, they described how the auction process from issuance of the Initial Auction Information Pack to running the Auctions is approximately six months. They suggested that a T-4 auction in September, four years prior to the Capacity Year and a T-1 auction in March, six months prior to a Capacity Year would result in an efficient sequencing of the Auctions as it would avoid overlap in the above six-month cycle.

2.4 SEM COMMITTEE RESPONSE

2.4.1 The SEM Committee notes that there was general consensus with the idea of holding a single auction for the balance of CY 2017/18 and full CY2018/19, and for making CY2021/22 a transitional year, so that the first T-4 Auction would now be in respect of CY2022/23.

2.4.2 The SEM Committee recognises that the issue of holding the transitional auctions in sequence before the first T-4 auction was raised by market participants in response to the consultation prior to CRM Decision 2 (SEM-16-022) on Transitional Issues, and then again in the consultation prior to CRM Decision 3 (SEM-16-039) on Auction Timing and Volumes. In SEM-16-039, the SEM Committee noted the following reasons why it may not be practical / appropriate to hold all the transitional auctions in sequence before the first T-4 auction:

- Compressed lead times associated with developing and implementing the Capacity Market Code and the auction system;
- The SEM Committee is keen to allow the practical lessons learnt from the auction for the first transitional year to be incorporated into auctions for the subsequent transitional years. It may take time to incorporate lessons learned in changes to the Capacity Market Code and auction systems;
- In order to facilitate new entry (competition and efficiency criteria), the SEM Committee wants to conduct T-4 auctions as soon as possible, and hence there is not expected to be sufficient time for a series of transitional auctions to take place for the intervening Capacity Delivery Years in advance of the first T-4 auction.

2.4.3 Further to this, in SEM-16-039 the SEM Committee noted that, “depending on the outcome of the first transitional auction (e.g. if little change to the auction system or Capacity Market Code is required), it may be possible to procure a significant proportion of the capacity requirement for the other transitional years through a sequence of T-3 and T-2 transitional auctions (coupled with later residual T-1 auctions for these years) prior to the first T-4 auction. However, at this stage, the SEM Committee makes no commitment in this regard”.

2.4.4 Since the publication of SEM-16-039 in July 2016, the RAs have worked with the TSOs to define the processes around qualification and the auction, and the TSOs have responded to this consultation. The TSOs have emphasised the difficulty in holding multiple auctions for different years, with different parallel Qualifications at the same time. This makes it unlikely that it will be possible to hold all transitional auctions in sequence before the first T-4 auction.

2.4.5 The SEM Committee notes that if it held the other Transitional Auctions in sequence before the first T-4 auction, this would not obviate the need for subsequent T-1 auctions for CY2020/21 and CY2021/22, given the need to hold back volume to T-1 timescales in order to facilitate DSU participation, etc.

2.4.6 The SEM Committee notes the points made by respondents about the lack of specificity in the auction timetable as set out in the CMC draft issued as SEM-17-004a, and will also consider the points made in the context of its decision on the final draft of the CMC.

2.5 DECISION

2.5.1 The SEM Committee has decided to have a single auction with a single Qualification process for the approximately 16-month period from go-live (anticipated 23 May 2018) to 30 September 2019:

- There will be a single Qualification process. Capacity providers must Qualify for both the 4-month period from go-live to the end of CY2017/18 and CY2018/19, or opt out of both periods;
- A single set of Auction Parameters will be defined, appropriate for CY2018/19;
- Bidders will submit a single bid price for both periods; and
- There will be the same clearing price for both CYs, and the same volume of Reliability Options will be awarded to the same bidders in CY2017/18 (a 4-month Reliability Option) and CY2018/19 (a 12-month Reliability Option).

2.5.2 The SEM Committee has decided to make CY2021/22 a transitional year, so:

- The first T-4 auction will be in respect of CY2022/23, and would be held just over 4 years in advance of the start of the CY, in late August 2018 or early September 2018;
- We will not hold a T-4 auction for CY2021/22 but will procure all capacity for CY2021/22 through a transitional T-1 auction; and
- The Capacity Requirement for all transitional years 2018/19, 2019/20, 2020/21 and 2021/22 will be based upon the demand forecast for 2021/22.

2.5.3 In response to requests for more clarity on the timetable for the enduring auctions the SEM Committee will consider this feedback further in the context of the CMC consultation (SEM-17-004), also further detail on the timing of the first transitional auction is outlined below.

2.6 HIGH LEVEL TIMETABLE FOR FIRST TRANSITIONAL AUCTION

2.6.1 The expected timetable for the first Transitional Auction is set out in Table 1. This plan reflects the milestones published by the TSOs in the Transitional Registration Plan V3.0 on 13th February 2017[4], and explains the significance of the key dates set out in this plan, and other key milestones. The table also denotes which milestone are Level 1 and Level 2 milestones in the I-SEM plan, and are therefore subject to change control processes.

[4] http://www.sem-o.com/ISEM/General/Transitional%20Registration%20Plan.pdf

Table 1: Key milestones for the first Transitional Auction

Key milestone [milestone number]	Description	Date
CMC issued [38]	The Capacity Market Code is issued for signature and Parties can accede to the Code from this date. Only once they have acceded to the Code can they submit their Qualification application for the first Transitional Auction	02/06/17
Initial Auction Information Pack issued	The CRM Delivery Body will publish the Initial Auction Information Pack which sets out, in one place, key information which auction participants are likely to want to know to help them Qualify and then bid in the auction. The minimum requirements for the data to be published will be prescribed in the CMC (Clause D.3 of the version issued as SEM-17-004a), but may contain other information the CRM Delivery body considers useful. Some of this information will have previously been published, for instance in this document, whereas some of the information will be new information (e.g. the definition of the constrained zones). Some of this information will be provisional, and be updated following Qualifying (e.g. the demand curve).	03/07/17
Qualification begins	This is the first date on which a Capacity Provider can submit its Qualification application to the CRM Delivery Body for the first Transitional Auction, once it has acceded to the CMC. This is also the first date on which a Capacity Provider can submit its application for a Unit Specific Price Cap (USPC) to the RAs.	03/07/17
Deadline for Unit Specific Price Cap (USPC):	This is last date on which a Capacity Provider can submit its application for a Unit Specific Price Cap (USPC) to the RAs. All information to support the USPC application must be submitted to the RAs by this date.	28/07/17
Unit Qualification Application Deadline [33]	Qualification closes. This is the last date on which a Capacity Provider can submit its Qualification application to the CRM Delivery Body for the first Transitional Auction.	28/07/17
Provisional Qualification results issued	The CRM Delivery Body will notify each applicant of the results of its Qualification on each of its capacity market units. Key results for each unit will include: whether it has Qualified or not and its de-rated MW eligibility; how many MW is eligible for a multi-year Reliability Option. Applicants will only be informed of their own results. The RAs will notify each USPC applicant of the result of its bid: whether it has got a USPC and how many de-rated MW the USPC relates to and the results of Opt-Out Notification if relevant.	06/10/17
Final Qualification results issued	Applicants will be notified of any changes following appeals	01/12/17

[164]		
Final Auction Information Pack issued [165]	The CRM Delivery Body will publish an update to the Initial Auction Information Pack, following approval of these values by the SEM Committee. This update will contain all final parameters to be used in the auction. Many of the parameters are likely to have the same value as the provisional values contained in the Initial Auction Information Pack, but some are likely to be different (e.g. the demand curve will be adjusted for non-mandatory bidders which have opted not to bid during Qualification, but are not closing)	01/12/17
Mock auction [182]	A practice auction for both bidders and the CRM Delivery Body to test their systems and processes. CRM Delivery Body will flag any issues. Mock results will not be made public.	04/12/17
First auction [36]	Actual date for first Transitional Auction. The auction is a "simple sealed bid" format, i.e. one round, and offers for the first Transitional Auction must be submitted on this day. However, results will not necessarily be notified this day	15/12/17
Provisional auction results	The CRM Delivery Body will publish the provisional results on this day.	18/12/17
Final auction results	After the Auction Monitor has provided its report to the SEM Committee, the SEM Committee will approve the auction results (subject to the report findings) and they will become final. The CRM Delivery Body will publish the final auction results, and the Reliability Options will be deemed to have been awarded on this date.	25/01/18
Performance Bonds lodged	Successful new (uncommissioned) capacity, but not existing capacity will be subject to Termination Fees, and will be required to lodge Performance Bonds to cover the Termination Fee liability.	Feb 2018

Denotes a Level 1 milestone in the I-SEM Plan; Denotes a Level 2 milestone in the I-SEM Plan.

3 ADMINISTRATIVE SCARCITY PRICING PARAMETERS

3.1 INTRODUCTION

3.1.1 In CRM Decision 1 (SEM-15-103), the SEM Committee decide that:

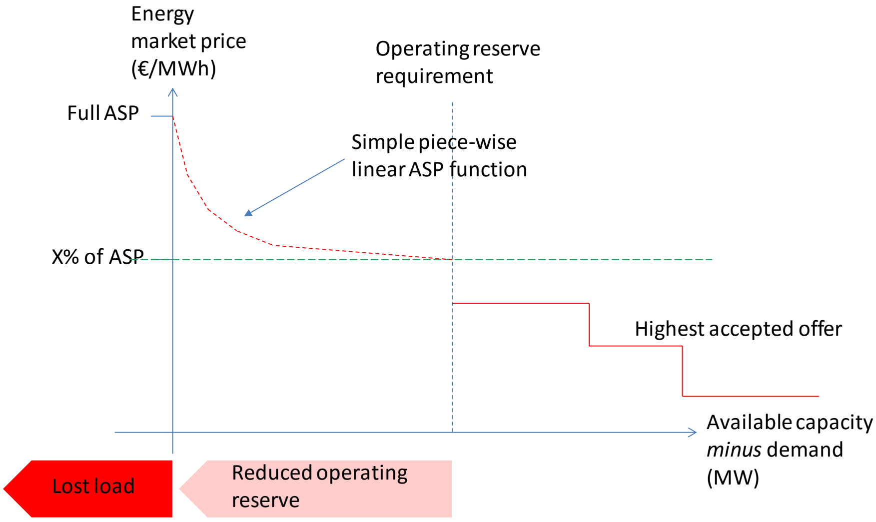
- Administrative Scarcity Pricing will be introduced into the energy imbalance price.
- Scarcity (for the purposes of Administrative Scarcity Pricing) will apply when there is insufficient available capacity to cover the combination of demand and the target level of operating reserve. Administrative Scarcity will not apply where operating reserve is reduced below target levels because the TSOs use reserve which has already been deployed (for instance to cover a forced outage), but additional capacity is available to replenish reserve.
- A simplified piece-wise linear approximation will be applied to calculate the ASP during a period where there is insufficient capacity to maintain target operating reserve, but load is not being shed. The BM price in any such Settlement Period will be the higher of the simplified piece-wise linear function, or the BM price as otherwise determined by the I-SEM ETA Markets Building Blocks Decision Paper (SEM-15-064).

3.1.2 Subsequent related decisions made in CRM Decision 2 (SEM-16-022) are outlined below:

- Administered Scarcity will be triggered when an event corresponding to any Customer Voltage Reduction, Planned or Emergency Manual Disconnection or Automatic Load Shedding either as defined in the SONI Grid Code or a direct equivalent event defined in the Eirgrid Grid Code is declared.
- Target Operating Reserve will be deemed to have been depleted if operating reserve (i.e. POR, SOR, TOR1 and TOR2) cannot be replaced from replacement reserve or ramping within one hour.
- The value of Full ASP will be set at the Euphemia day ahead price cap of €3,000/MWh. This will exist throughout the transition period, after which it will be based on VoLL. The exact percentage of VoLL used will be defined at a later point in time, but will be no greater than 100%. To ensure suitability, the VoLL calculation will be reviewed on a regular basis.
- The piece-wise linear function will be static, with MW of operating reserve used as the basis for its definition. The price from which the function begins will be the Reliability Option Strike Price.

3.1.3 The piece-wise linear function was illustrated in CRM Decision 2 by Figure 4, and to aid the systems specification we instructed the TSOs that the piece-wise linear function would have no more than 5 line segments.

Figure 4: Piece-wise linear ASP function



3.2 CONSULTATION SUMMARY

3.2.1 The CRM Parameters consultation (SEM-16-073) sought to determine the values of the Partial Administrative Scarcity Price (Partial ASP) that will apply when Administrative Scarcity Pricing has been triggered, but full load shedding has not yet occurred, i.e. defining the values of the dotted red line in Figure 4 above.

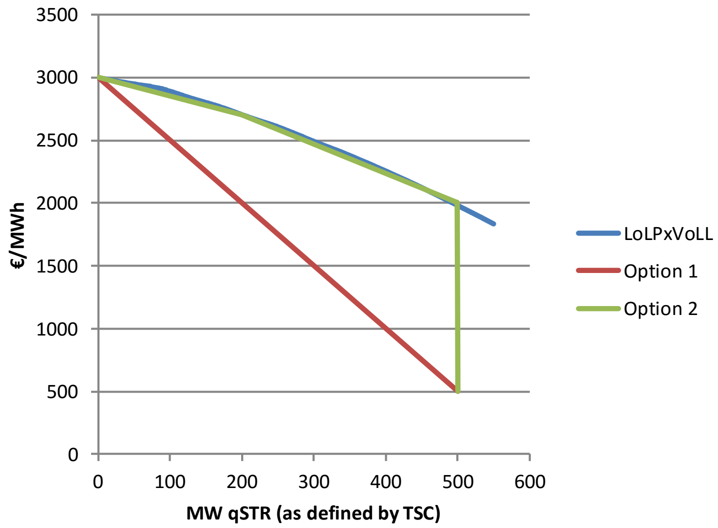
3.2.2 The policies set out in CRM Decision 1 and 2, are being implemented in the Trading and Settlement Code (TSC) drafting, which was consulted upon separately (see SEM-16-075). Key points to note within the TSC drafting were outlined within the parameters consultation paper and related to the trigger for the application of the ASP, the quantity of Required Operating Reserve and the definition of scarcity.

3.2.3 Two options for the Partial ASP function were consulted upon, which were both simple piece-wise linear approximations to the LoLP curve multiplied by the Value of Lost Load (VoLL). The two options, which are depicted in Figure 5 are:

- **Option 1:** Simple linear function. This option would introduce the ASP at a relatively low level, consistent with a transitional approach to implementing ASP. As illustrated in Figure 5, Option 1 generates prices which are not such a close approximation to the product of Loss of Load Probability (LoLP) and the Value of Lost Load (VoLL). Figure 5 illustrates the fact that once qSTR falls as low as 500MW (being the single largest infeed) LoLP x FASP = €2,000/MWh since there is a 66% chance that load will be lost and prices will rise to €3,000/MWh.
- **Option 2:** A LoLP x VoLL approximation. In this option, the ASP would be a simple two-piece linear function, which would be a reasonable approximation of the value of the product of the Loss of Load Probability and the FASP, as a function of the remaining

available operating reserve. This way, the Partial ASP will be a good approximation to probability of lost load x price of lost load[5].

Figure 5: Partial ASP function options



3.3 SUMMARY OF CONSULTATION RESPONSES

3.3.1 The majority of respondents expressed a preference for Option 1 (linear curve). A conservative approach was favoured initially, with Option 1 introducing less energy price volatility as a result of Partial ASP than Option 2. Respondents cited the uncertainty that exists with respect to the functioning of the new I-SEM and lack of operational experience with participants exposed to balancing risk as key reasons for favouring lower energy price volatility, at least initially.

3.3.2 Other respondents in favour of Option 1 argued that Option 2 has other drawbacks such as Option 2:

- Relies on estimations of both VoLL and LoLP;
- Will result in higher prices having to be borne by consumers;
- May create perverse incentives to trigger the reserve pricing function for participants with a portfolio of contracted and uncontracted plant.

[5] The SEM Committee considered the alternative of making the function an approximation of LoLP x VoLL but capping the price at FASP. However, if this option was pursued, the ASP would hit the FASP cap, as soon as the LoLP reached around 25% (3,000 FASP / 11,000+ VoLL), and the FASP would likely apply over a range of occasions where operating reserve was reduced below target, short of full load shedding.

3.3.3 One respondent in favour of Option 1, stated that if a curve is required to follow the shape of a LoLP curve (as Option 2 does), then it should begin at a much larger reserve margin and much lower price.

3.3.4 Those respondents favouring Option 2, cited the following arguments:

- It generates stronger penalties for non-delivery which will penalise non-reliable capacity, improving exit signals;
- Cost reflective. One respondent argued ASP should be as close as possible to real cost (for which Option 2 is a proxy). Another respondent described how Option 2 reflects a true value of the probability of lost load and is the correct market signal that should apply.

3.3.5 Some respondents (including those who expressed a preference between Options 1 and 2) argued in favour of other options not presented in the consultation. These included approaches based on the curve as illustrated in Figure 4, which has a gentle slope initially and a steeper slope as zero reserve is approached, providing a progressively increasing incentive for generation to be available as operating reserve reduces.

3.3.6 One respondent suggested there appeared to be a mismatch between the probability of lost load within an hour within Figure 4 of the consultation paper (reproduced in this paper as Figure 5) and a statement that at 600MW of operating reserve there is a greater than 55% chance of lost load as shown in Figure 3 of the consultation paper. Also, clarification was sought that the shape of the Partial ASP function is not intended to change from year-to-year.

3.3.7 One respondent stated there is a transparency issue regarding the visibility of scarcity signals for market participants, suggesting rules need to be defined as to when the TSOs can take early load shedding actions, causing FASP.

3.4 SEM COMMITTEE RESPONSE

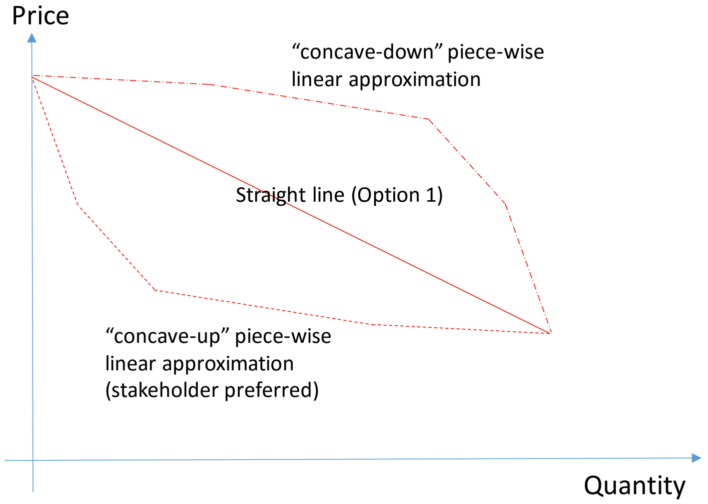
3.4.1 The SEM Committee agrees with the majority of respondents, who argued that Option 1 is preferable because it will result in lower price volatility, with lower average Partial ASP values than Option 2, and that Option 1 is arguably more consistent with a transitional approach as a result. Price volatility may be appropriate where it reflects volatile costs, but there should be a balance between price volatility (and hence risk) and other objectives.

3.4.2 In making its decision, the SEM Committee notes that the Partial ASP function sets a *minimum* price, so that if the market trades in the Balancing Market at prices above the Partial ASP function, market determined prices shall prevail. Option 1 therefore does not preclude higher prices, where the market determines that costs are higher than Partial ASP.

3.4.3 The SEM Committee notes that both Options 1 and 2 differ from the shape of curve illustrated in some previous papers (and repeated as Figure 4 in this paper), where the illustrative curve was "concave-up". However, as we made clear in those documents, the curve shown in the diagram was only *illustrative,* and reflected the expectation of the shape of the LoLP curve at an early point in the project. However, further analysis reveals that the LoLP curve is actually "concave-down" in the range where Partial ASP, since LoLP is already quite close to 1 by the time reserves are below 300MW, and the LoLP curve is quite flat at a high level. This is because when reserves fall to this level, the loss of one unit is quite likely to trigger load shedding since there are a quite a number of unit in the range 300MW+, and if there are only 300MW of reserve, the chances are quite high that at least one of these units will suffer a forced outage resulting in lost load.

3.4.4 The SEM Committee does not favour some of the other options suggested by respondents, which generally reflected the illustrative shape set out in Figure 2 of the CRM Parameters consultation, i.e. was "concave up"(see Figure 6) . This is the opposite direction to the change of the slope of the LoLP x FASP curve, which starts out steep initially as reserves decline, flattening out later as reserves approach zero (i.e. is "concave-down"). A Partial ASP function which is "concave-up" is less cost reflective than Option 1.

Figure 6: Illustration of stakeholder preference



3.4.5 Respondents sought clarification regarding the LoLP figures discussed in SEM-16-073. Figure 3 of SEM-16-073 showed that there was a probability of lost load of around 55% when there is only 600MW of reserve available. Figure 4 showed a range starting at only 500MW of reserve available. At this point LoLP x FASP is €2,000/MWh. Since FASP is €3,000/MWh, this implies that by the time reserves have declined to 500MW, LoLP has risen to 67%- i.e. reflected the expectation that LoLP rises as available reserves fall.

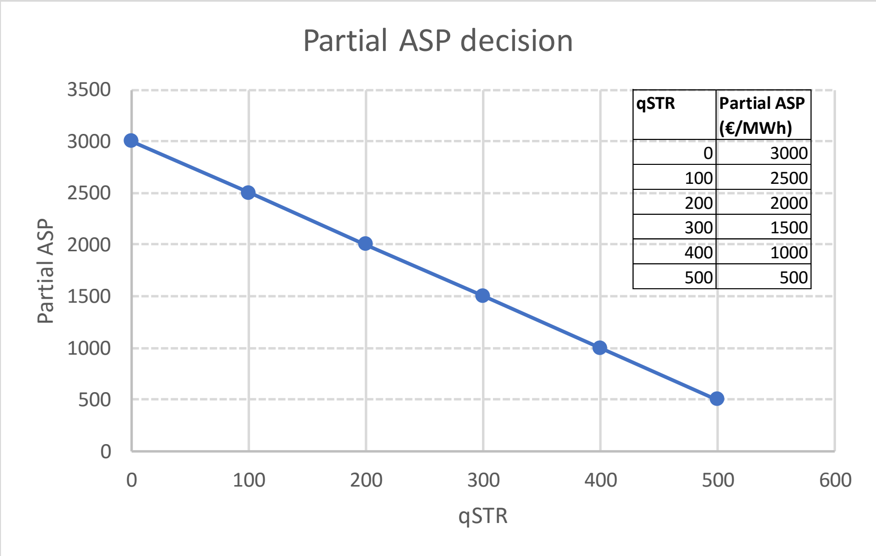
3.4.6 The SEM Committee agrees that there should be maximum possible transparency in relation to when the TSOs can take early load shedding actions, causing FASP and we will work closely with the TSOs to ensure this is the case.

3.4.7 The SEM Committee can clarify that the shape of the Partial ASP curve is not intended to change from year to year. The shape may change however, through modification to the TSC in accordance with normal TSC governance processes. Whilst the shape of the curve is not intended to change, the level of Partial ASP will change when the value of FASP is increased from the transitional value of €3,000/MWh to the enduring VoLL based value.

3.5 SEM COMMITTEE DECISIONS

3.5.1 The SEM Committee has decided to implement Option 1 for the Partial ASP function, representing a balance on price volatility. This is shown in Figure 7 below:

Figure 7: Partial ASP function decision



3.5.2 To clarify, according to the approach set out in the TSC, ASP only applies when the available Short Term Reserve (qSTR) is less than the operating reserve requirement (qORR). Therefore, if the operating reserve requirement is only 450MW, and the available Short Term Reserve falls to 490MW, the ASP function above does not apply, and prices will be market determined.

4 COST RECOVERY AND CHARGING

4.1 INTRODUCTION

4.1.1 In CRM Decision 1 (SEM-15-103) the SEM Committee decided that costs of capacity will be recovered from Suppliers as a fixed €/MWh charge across demand in a pre-defined set of half hours (called the Supplier Charging Base) that are judged to be those most likely to have high LoLP values.

4.1.2 The CRM Parameters Consultation (SEM-16-073) posed two key questions with respect to Supplier Charging Parameters:

- **How should the Supplier Charging Base be defined**? Which half hours should be defined as the “Supplier Charging Base[6]”; and
- **What interest rates should be payable in respect of balances in the Socialisation fund**. The early versions of the CRM Settlement Rules contained within the TSC include a provision for Base, Deficit and Surplus interest rates to be paid on balances in the Socialisation fund. However, the version of the TSC issued for consultation (as SEM-16-075) does not contain reference to Socialisation fund specific interest rate parameters. Therefore, **these specific interest rate parameters are not necessary. Any decision required in relation to interest rates on funds will be considered separately by the RAs.**

4.1.3 The focus of the rest of this Section is therefore entirely on the definition of the Supplier Charging Base.

4.2 CONSULTATION SUMMARY

4.2.1 Based upon historical data provided by the TSOs in relation to LoLP over the years, certain patterns were summarised in the consultation paper which were comparable with LoLP patterns found in other electricity systems. This analysis was used to form the following three options which were detailed within the consultation paper:

- **Option 1:** A highly focused Supplier Charging Base focusing Supplier charges on the peak period (5pm to 9pm) in Winter quarters;
- **Option 2:** A focussed Supplier Charging Base, with Supplier charges focused on the period 5pm to 9pm throughout the year; and
- **Option 3:** A broader based Supplier Charge, with Supplier charges focused on a broader day-time period from 7am to 11pm in all quarters.

[6] In the latest draft of the TSC, the Supplier Charging Base is not explicitly referred to. The TSC gives effect to the Supplier Charging Base through the use of the Capacity Charge Metered Quantity Factor (FQMCCy). Effect will be given to the Supplier Charging Base by assigning the value 1 to FQMCCy in Imbalance Settlement Periods which form part of the Supplier Charging Base, and the value 0 to ISPs which do not form part of the Supplier Charging Base.

4.2.2 In assessing the above options, the consultation paper considered the possibility of cash flow issues for Suppliers and also how the proportion of the Supplier charge borne by the residential customers under Options 1 to 3 differed from under the SEM. Based upon analysis presented in the consultation paper the SEM Committee favoured Option 3 for the foreseeable future. The key reasons for favouring Option 3 were:

- The LoLP analysis is not entirely conclusive, with patterns not entirely consistent across recent years (other than LoLP is low from 11pm to 7am), which favours a broader base of hours for charging;
- Given that there is no clear seasonal pattern or pattern within daytime hours, there does not seem to be adequate justification for implementing options such as 1 and 2 which would have a significant increase in the share of charges to residential customers, and reduction in the share of charges borne by industrial and commercial customers. By contrast, Option 3 will have a relatively limited impact on the share of charges borne by residential customers versus industrial and commercial customers.

4.2.3 Regardless of which option is chosen for the first Capacity Year, the Supplier Charging Base should be kept under review by the SEM Committee, acknowledging that the pattern of LoLP may change over time in response to the growth of intermittent generation, and as capacity providers respond to entry and exit signals provided by I-SEM CRM.

4.2.4 The SEM Committee welcomed views as to which of Options 1 to 3 is the most appropriate and why. Alternatively, other definitions of the Supplier Charging Base could be provided together with justification.

4.3 SUMMARY OF RESPONSES

4.3.1 The majority of respondents favoured Option 3, with this option being cited as closer to the current approach to charge allocation. Respondents agreed that Options 1 or 2 would increase the cost to residential customers, and some noted that it is difficult for residential customers to respond to sharper price signals by altering demand consumption during peak times.

4.3.2 Other respondents cited a range of issues to do with the level of uncertainty around the LoLP values, and changing LoLP pattern as reasons for a broader based charge, such as Option 3. Factors cited include the reducing correlation between peak demand and scarcity, due to the growth of intermittent renewables, and the greater uncertainty over the distribution of LoLP it creates. One respondent argued that historic LoLP is somewhat of a misnomer since demand was known and was either met or not, hence no forecast range, no probability, and questioned the values presented in Figure 5 of SEM-16-073 as a result (we address this issue in paragraph 4.4.4).

4.3.3 A number of respondents cited a range of cash flow related issues, for favouring Option 3:

- One respondent described how, with Option 3 the charging base will be spread throughout the year somewhat in sync with the option fee payments, reducing cash flow issues for the CRM Delivery Body and the socialisation fund. Another respondent supporting Option 3 stated that given the revised go-live date (in late May 2018), it

facilitates the build-up of funds into the Socialisation Fund from the beginning of the I-SEM, whereas Option 1 would not support the build-up of funds during summer months.
- A number of respondents mentioned the cash flow issues Options 1 and 2 present for Suppliers.

4.3.4 Other respondents argued that a narrower Supplier Charging Base could have other unintended consequences. One respondent argued that, with Options 1 or 2 there is a risk that larger customers will be incentivised to run backup generation during peak hours in order to avoid excessive capacity charges with negative environmental consequences. One respondent described how Triads (a narrow charging base for GB transmission charges) has encouraged larger consumers to power up on-site generators; and this has burdened smaller consumers with higher costs, and results in less accurate demand forecasts during these times.

4.3.5 It was also argued that there is a potential for greater forecast error against a smaller Supplier Charging Base and the potential for higher prices as a result to account for these forecast errors. Another respondent suggested how sharper price signals could create an incentive for customers to move demand in an unpredictable way, on local nodes heavily loaded with wind energy, an inappropriate price signal for customers to reduce demand.

4.3.6 Another respondent argued how focusing the Supplier Charging Base only on the winter period, as proposed in Option 1, is not wholly consistent with the CRM’s high level design.

4.4 SEM COMMITTEE RESPONSE

4.4.1 The SEM Committee agrees with the majority of respondents that Option 3 is the most appropriate approach given:

- Cost-reflectivity: There is no clear seasonal / time of day pattern in LoLP other than the lower LoLP during the night time period (11pm to 7am), and no particular period has a high LoLP. This option is therefore cost reflective, in that it allocates charges reasonably in proportion to the probability of scarcity in that period and delivers an economically efficient pricing signal;
- Practicality:
    - It represents least change to the incidence of charges between residential and industrial and commercial customers, which is the most practical approach in the absence of significant evidence in favour of a change;
    - **It does not have some of the cashflow issues** associated with Option 1 in particular, given that the I-SEM will go-live in May 2018 (and hence pay Reliability Option fees from May 2018), but not receive charges from Suppliers until October 2018.

4.4.2 The SEM Committee also notes some of the points made by respondents that a narrow Supplier Charging Base could lead to incentives on large consumers to invest in less efficient back-up generation to avoid capacity charges during a narrow peak, with **adverse environmental consequences**, and other potential adverse consequences of a narrower charging base, such as “shifting peaks”. In addition, a key source of potential load growth, data centres, would also be expected to lead to an increase in demand over a broad range of hours.

4.4.3 The SEM Committee notes that different LoLP patterns may evolve over time, as the level of intermittent output stabilises at a new higher level, and as existing plant responds to exit signals- which may sharpen the LoLP profile. At such time, the SEM Committee may choose to review and change the definition of hours within the Supplier Charging Base.

4.4.4 The SEM Committee does not agree with the respondent who argues that historical LoLP is not an appropriate basis on which to set the Supplier Charging Base, and who argues that ex post, LoLP is either 1 or 0. The “ex-post” LoLP figure used for our analysis is produced under the current SEM, and is calculated according to Appendix M of the SEM Trading and Settlement Code. This uses the ex-post (i.e. outturn) margin and applies it to the static LoLP curve. In a trading interval with zero margin the result would be an ex-post LoLP of 1. For all other values of margin, it would result in a LoLP between 0 and 1. It is of course true that after the event the actual LoLP would be binary, but the purpose of this ex-post LoLP (based on the ex-post margin) is to give the correct profile for setting the ex-post portion of the capacity payments in the current SEM.

4.5 SEM COMMITTEE DECISION

4.5.1 The SEM Committee has decided that it will implement Option 3 for the Supplier Charging Base, i.e. the cost of capacity in respect of any Capacity Year will be recovered by a fixed charge levied on Suppliers MWh of consumption that applies at the same rate on every day of the year from 7am to 11pm.

5 RELIABILITY OPTION PARAMETERS

5.1 INTRODUCTION

5.1.1 In the CRM Parameters consultation (SEM-16-073) we sought consultation feedback on the following Reliability Option parameters:

- The DSU floor price, called the Demand Side Unit Theoretical Price ($PTHEORYDSU_y$) in F.16.1.5 of the TSC;
- Carbon Intensity Factors, namely the Natural Gas Carbon Intensity Factor ($FCARBONING_y$) and the Oil Carbon Intensity Factor ($FCARBONIO_y$) in F.16.1.5 of the TSC;
- Transport Adders; and
- The Billing Period Stop-Loss Limit, as prescribed in D3.1.3 of the draft of the CMC issued for consultation as SEM-17-004a.

5.1.2 As we discussed in SEM-16-073, the Carbon Intensity Factors and the Transport Adders will depend in part on the fuel and carbon indices chosen to set the Reliability Option Strike Price. In CRM Decision 3 (SEM-16-039), the SEM Committee decided that the CRM Delivery Body will propose indices for approval by the RAs. Evaluation is ongoing and it is expected that the SEM Committee will make a decision on the fuel and carbon indices, the Carbon Intensity Factors and the Transport Adders in due course, taking into account feedback received during the CRM Parameters consultation. These fuel and carbon indices, Carbon Intensity Factors and Transport Adders will then be published in the Initial Auction Information pack to be issued in July. A summary of the consultation responses received with respect to the Carbon Intensity Factors and the Transport Adders is set out in Appendix B and C.

5.1.3 The rest of this section focuses on the DSU floor price, and the Billing Period Stop-Loss limit.

5.2 DSU FLOOR PRICE

Consultation Summary

5.2.1 CRM Decision 1 (SEM-15-103) stated that to facilitate DSU participation the SEM Committee plans to set a floor price to the Reliability Option Strike Price, the “DSU Floor Price”. The rationale for a DSU Floor Price is that:

- For environmental reasons, the SEM Committee wants to appropriately encourage investment in DSUs, and aims to increase the participation of DSUs in the I-SEM; and
- The SEM Committee was concerned that there may be a disincentive on DSUs to participate in the I-SEM CRM if DSUs have to pay difference payments at a threshold price which is less than the costs of providing the demand side response. This could be the result at times when fuel prices are low, if the Strike Price was a function of generation fuel prices, but not the costs of providing demand side response. Under such circumstances, there is a concern that a DSU Floor Price could interfere with the operation of the energy market.

5.2.2 SEM-16-073 noted that in CRM Decision 1, the SEM Committee also took another decision, which, at least for an initial period from I-SEM go-live, means that DSUs will not have to make Reliability Option difference payments at all, except when the demand reduction is not delivered[7]. This mitigates the risk that a low Strike Price will interfere with DSU participation in the capacity or energy market. However, SEM-16-073 still noted that, the SEM Committee still sees advantages in setting a DSU floor price to:

- Send appropriate longer term price signalling to DSU providers; and
- Provide a degree of simplification to the Reliability Option hedge if the Strike Price is constant most of the time (except when there is a fuel price spike).

5.2.3 SEM-16-073 stated that the level at which the floor price element should be set needs to balance a number of objectives, including:

- System security, and maximising the potential contribution of DSUs - which would favour a higher floor; and
- Limiting the incentive for generators to exercise market power in the energy market and providing a hedge to Supplier price risk, which would favour a lower floor.

5.2.4 SEM-16-073 discussed the key cause of complexity- treatment of DSU shutdown costs, and presented data on the costs of existing DSUs in Appendix B of SEM-16-073. Based upon this analysis the SEM Committee proposed a DSU floor value of €500/MWh as providing an appropriate balance and feedback was sought as to whether respondents agreed. This value of €500/MWh was not a surprise to market participants- it has been used consistently as a working assumption for the DSU Floor Price since CRM Decision 1 (SEM-15-103).

Summary of responses

5.2.5 The majority of respondents agreed with the proposed DSU floor price of €500/MWh. One respondent described how it strikes a balance between retaining performance incentives for generator units and incentives for supplier units to actively manage trade in the ex-ante

[7] In CRM Decision 1 the SEM Committee decided that a hybrid version of Options 1 and 3 from the Consultation Paper is the most appropriate treatment of DSUs for introduction from I-SEM Go-live. This hybrid option:

- Does not credit DSUs with the energy value of the demand reduction;
- Does not apply RO difference payments to DSUs when the contracted demand reduction is delivered;
- Applies an RO difference payment, only when the demand reduction is not delivered when the Strike Price is exceeded by the MRP.

This CRM 1 decision reflects the fact that for the time being, the energy value of the demand reduction accrues to the Supplier, not the DSU, and that it was not practical in the shorter term to make changes to energy settlement systems to credit the value of the energy saving to the DSU. However, CRM Decision 1 stated that "*on the medium to long term, the SEM Committee considers that there may be merit in further exploring Option 2* [making DSU make difference payments like generators] *and as such may review this decision post I-SEM Go-live*" markets. One respondent described how it will offer a degree of stability in the Reliability Option process as it is likely to be less volatile than other potential floor prices.

5.2.6 Of those respondents who dissented there was a range of responses, with some wanting a higher price and some wanting a lower price:

- Some wanted a higher DSU Floor Price: One respondent suggested that €500/MWh may be too low and needs to be increased slightly, and noted that 17% of existing DSUs shutting down for 1 hour have an associated shutting down cost in excess of €500/MWh. One respondent stated that the DSU floor price should be set to cover the prevailing cost of all existing demand side units;
- Of those wanting a lower price, one respondent suggested a value of €400/MWh as the floor price, and supported the view that the floor price should be set for DSUs initially but over the longer term DSUs should be treated in the same manner as existing capacity providers.

5.2.7 Other respondents did not necessarily venture an opinion as to whether the price was too low or too high, but raised questions over the approach or the data, including:

- One respondent suggested that the process for determining the DSU floor price should be supported by a key set of principles and a clear methodology in order to provide transparency and clarity in how it will change in the future. Another respondent asked to what extent the decision made in relation to the Strike Price Formula will be "static";
- One respondent questioned if it is indexed or static over the duration of the Reliability Option;
- One respondent described how the costs in Appendix B of the consultation paper may reflect a blend of DSU costs from the costs of operating back-up generation to some estimation of pure demand reduction shutdown costs, so consequently careful interpretation may be required in using these costs as a DSU floor price for I-SEM. Another respondent requested the RAs draw on a wider sample period than was undertaken in Appendix B.

SEM Committee Response

5.2.8 The SEM Committee views the €500/MWh as striking an appropriate balance between the objectives set out in the consultation paper (SEM-16-073) and summarised above.

5.2.9 As noted by a respondent, only 17% of existing DSU capacity (55MW) would fail to recover its shutdown costs over a 1 hour shutdown, and relatively large increases in the DSU floor price would be required to meet the shutdown capacity of this residual 17%. No additional capacity would be able to recover its costs within one hour by increasing the floor price to €1,000/MWh, and only 20MW would be able to recover its costs by increasing the floor to €1,500/MWh.

5.2.10 The SEM Committee prefers a floor of €500/MWh to a value of €400/MWh since a number of existing DSUs have incremental costs in the €300-350/MWh range, and would be less likely to cover their shutdown costs, during a scarcity event, once DSUs are required to make difference payments- i.e. a Strike Price at this level is less compatible with the long-term vision for DSU treatment.

5.2.11 As noted above, in CRM Decision 1 (SEM-15-103) the SEM Committee decided that, at go-live, a DSU will only be required to make difference payments if it fails to deliver the demand response consistent with its Reliability Option MWs, so recovery of shutdown costs is less of a concern anyway. Consider a scenario whereby the shutdown cost of a DSU is €2,000/MW and it has an incremental cost of €600/MWh. Now suppose that a 1 hour shutdown is requested by the TSOs in response to a scarcity event, and that the market price rises to the full ASP of €3,000/MWh. The consumer incurs a cost of €2,600/MW of RO, but if it provides 1 MWh of demand response, its Supplier should earn €3,000/MWh selling the energy back into the relevant spot market- money which can be used to cover the consumer's costs. If the consumer fulfils its contractual obligation, and the retail supply contract is appropriately structured between the consumer and the Supplier, the consumer will have a cost of €2,600/MW for the shutdown, but a revenue of €3,000/MW making a net profit of €400/MW as a result of the shutdown. By contrast, if the consumer does not provide the demand response, it will have to make a Reliability Option difference payment of €2,500, without offsetting energy market revenues from selling back power. This worked example demonstrates that, given the "Day 1" arrangement set out in SEM-15-103:

- DSUs will not necessarily be disincentivised from participating in the CRM mechanism, even if their shut down costs are significantly greater than DSU floor price; and
- If they do participate, they will be incentivised to deliver on the demand reduction.

5.2.12 The DSU floor price should be set low enough to support equity and efficiency objectives by providing Suppliers with a meaningful hedge to price spikes, and ultimately protecting consumers against these price spikes too. The Reliability Option hedge was identified as one of the key benefits of the High-Level Design. Conversely, the DSU floor should not be set so low as to discourage DSU participation in the capacity market. These are the guiding principles behind the level of the DSU floor price.

5.2.13 The SEM Committee recognises that some participants would like a more deterministic approach to setting the level of the DSU Floor Price and how it will evolve over time than the high-level principles set out in the consultation paper (SEM-16-073). However, the SEM Committee does not believe that it is appropriate to set out a deterministic methodology for determining the DSU floor price for the time being, as it remains to be seen how DSU participation evolves in the I-SEM, and whether DSUs react differently to incentives within the I-SEM CRM and energy market.

5.2.14 Furthermore, the SEM Committee believes it would be challenging to set deterministic rules without reliance of somewhat arbitrary assumptions, and/or without the risk of unintended consequences. For instance, one respondent implied that the deterministic rule should be to allow all existing capacity to recover its shutdown costs within a 1 hour period. The problem with such a deterministic rule is that it would require, a very high Strike Price, and there is no guarantee that a DSU will only be required to shutdown for one hour. Evidence presented in SEM-16-073 (Appendix B), showed that for all existing DSUs to be able to recover their shutdown costs within one hour, would require a DSU floor price of €2,600/MWh. This level is far too high to provide a meaningful hedge to Suppliers. If required to shutdown for only half an hour, it would not be feasible for all existing DSUs to recover their shutdown costs, even if they were paid the Full ASP for half an hour for energy sold back into the spot market, and even if they were not required to make any difference payments.

5.2.15 The key difficulty is that DSU costs include a shutdown cost in €/MW per event, and an incremental cost in €/MWh. The minimum shut down time for existing DSU is not limited to 1 hour or even ½ an hour, so inevitably assumptions have to be made about the likelihood of short shutdown periods, or to set the Strike Price at such a high level that it will provide a very limited hedge to suppliers, and have little impact on the ability of generators to extract excessive rent.

5.2.16 One respondent questioned whether the DSU Floor Price would be indexed over the length of a multi-year Reliability Option. DSUs will be eligible for multi-year Reliability Options where they meet the relevant criteria, including the New Capacity Investment Rate Threshold (NCIRT). It is anticipated that there will be relatively few occasions when DSUs will meet the NCIRT. However, it is not intended that the Strike Price will be automatically indexed. The DSU floor price will be reviewed periodically (although not necessarily as frequently as annually) based on market conditions. The nominal value in respect of a Capacity Year will be notified in the Initial Auction Information Pack. This nominal value would normally be expected to pertain through the T-1 auction (where the majority of DSU capacity is expected to be procured) and throughout the delivery period. However, the SEM Committee may choose to increase the DSU floor price between the T-4 auction and the T-1 auction, if it felt that there was a material increase in DSU costs in the intervening three years, so an increase was appropriate to retain DSU participation. That increase in costs could be driven by inflation, or by other factors. Where the DSU floor price was increased between the T-4 and T-1 auction (or any two auctions in respect of the same delivery year) the higher DSU floor price would apply to all Reliability Option for that delivery year, regardless of which auction they were awarded in.

5.2.17 The SEM Committee notes that the Reliability Option fee is not indexed either, a decision made in CRM Decision 2 (SEM-16-022).

5.2.18 One respondents asked for data on a wider range of DSUs to be taken into account than was presented in Appendix B of SEM-16-073. However, the SEM Committee wishes to clarify that:

- Data was presented for all existing DSUs in the SEM, not just a subset; and
- Whilst bids vary from day-to-day, they have not varied that much. DSU bid data (including start-up costs) is in the public domain and stakeholders can validate the variability themselves.

SEM Committee Decision

5.2.19 The SEM Committee has decided to set the DSU floor price, called the Demand Side Unit Theoretical Price ($PTHEORYDSU_y$) in F.16.1.5 of the TSC, at €500/MWh.

5.3 BILLING PERIOD STOP-LOSS LIMIT

Summary of consultation

5.3.1 In CRM Decision 1 (SEM-15-103), the SEM Committee decided that Stop-Loss Limits would apply. These Stop-Loss Limits cap a capacity provider's exposure to uncovered difference payments. Uncovered difference payments are difference payments that occur when the capacity provider is unavailable, so, absent the Stop-Loss Limit, it would have to make difference payments without receiving commensurate revenues from the energy or ancillary service market.

5.3.2 In CRM Decision 2 (SEM-16-022) the SEM Committee further decided that:

- For the start of the CRM, an Annual[8] and a per Billing Period Stop-Loss Limit will be used[9], where the billing period was defined as the period between the physical delivery of electricity and the time at which I-SEM payments will occur;
- The Annual Stop-Loss Limit will be set to 1.5 x the annual option fee for a capacity provider;
- It was minded to set the Billing Period Stop-Loss Limit to 0.5 x the Annual Stop-Loss Limit (i.e. 0.75 x the annual option fee). However, at the time of CRM Decision 2, the Billing Period had not been decided, so the decision on the final value of the Billing Period Stop-Loss Limit multiple was deferred to the CRM parameters consultation process.

5.3.3 Since the CRM 2 decision (SEM-16-022) the definition of billing/settlement periods to be included in the Trading & Settlement Code have been progressing, and a Billing Period is defined as a week and is used for imbalance and difference payment settlement[10].

5.3.4 The key reasons not to set the Billing Period Limit multiple too low are that, in a given Billing Period, it blunts the incentive to perform and increases the potential size of the "hole-in-the hedge" (i.e. difference payments to suppliers which are not balanced by payments from Capacity Providers). However, setting the Billing Period multiple too high could mean that

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[8] Per Capacity Year

[9] There are benefits to aligning the stop-loss limit with the billing period used for energy settlement. This will increase the possibilities for netting off payments and charges in settlement and will help to manage the credit risk from participants and improve the efficiency of the market. In consequence, the SEM Committee decided to use a stop-loss limit aligned with the settlement billing period, rather than use a monthly stop-loss limit.

[10] A Capacity Period is defined as a month and is used for capacity payment/charge settlement. In line with SEM-16-022, it is the Billing Period, rather than the Capacity Period, to which the shorter stop-loss limit will apply. This is logical, because Reliability Option difference payments are intended to provide Suppliers with a hedge against energy prices in excess of the Reliability Option Strike Price, so should align with the timing of energy payments by Suppliers.

after one or two events, a given Capacity Provider would no longer be incentivised by difference payments to perform.

5.3.5 In the CRM Parameters consultation (SEM-16-073), the SEM Committee stated that it remained minded to set the Billing Period multiple as 0.5 x the annual stop-loss limit (i.e. 0.75 times the Annual Option fee), but sought further feedback on this minded-to position.

Summary of responses

5.3.6 The majority of respondents did not agree with the minded to position of setting the Billing Period Stop-Loss Limit at a multiple at 0.5 times the Annual Stop-Loss Limit. Respondents suggested lower billing period stop-loss multiple values (times the annual stop-loss) of 0.125, 0.1875, 0.2, 0.25 and 0.33. Respondents cited how it is a departure from market expectations of a monthly stop loss limit, with the assumption previously that the Billing Period coincided with the capacity billing period i.e. monthly. A number of respondents suggested lowering the Billing Period Stop-Loss Limit to reflect this move from a monthly to a weekly limit.

5.3.7 A number of respondents described the balance of ensuring units face penalties for non-delivery in a billing period but also retain a meaningful incentive to be available in subsequent periods. On this basis they argued that the Billing Period Stop-Loss multiple value of 0.5 times the Annual Stop-Loss Limit is too high, given that a generator could reach its Annual Stop-Loss limit within two weeks (or potentially two days). Different respondents suggested lowering the billing period stop-loss limit to remedy this. Also, it was argued that the proposed limit places excess risk on Capacity Providers, and it was argued that a typically reliable participant could lose more than its entire year's capacity payment due to an unfortunately timed, but nevertheless rare outage.

5.3.8 One respondent requested that the Billing Period Stop-Loss decision is not finalised until the settlement systems can demonstrate that they can implement the Stop-Loss Limits. One respondent suggested an Annual Stop-Loss Limit of 1 for wind energy and would also welcome a lower Billing Period Stop Loss Limit for wind generation.

5.3.9 However, one respondent agreed with setting the Billing Period Stop-Loss limit at this level to balance the risk on capacity providers against the incentive to continue to provide capacity following a scarcity event.

SEM Committee Response

5.3.10 The SEM Committee thinks that the proposed Billing Period Stop-Loss Limit of 50% of the Annual Stop-Loss Limit (75% of the annual option fee) is appropriate, and achieves the appropriate balance between maintaining incentives during one scarcity event, and maintaining incentives across multiple events.

5.3.11 Respondents did not produce material new evidence as a result of the consultation. Most of the responses were from Capacity Providers trying to limit their exposure to penalties resulting from any failure to perform, and ensure that they make a net profit from the CRM even if they do not perform.

5.3.12 The SEM Committee re-iterates the following points, which have been made before and which it has factored into its decision:

- It is appropriate that any Capacity Provider which has failed to perform is subject to difference payments, and appropriate that these difference payments should potentially be larger than the option fee, since failure to perform in the event of scarcity can cause consumer detriment which exceeds the option fee;
- Overall risk is capped by the Annual Stop-Loss Limit as well as Billing Period Stop-Loss Limits;
- Capping the Billing Period Stop-Loss limit at too low a level could lead to an unnecessary "hole-in-the-hedge". E.g. if that is the only scarcity event in that year (or there are only two weeks with scarcity events in that year);
- With the current excess of capacity, the likelihood of scarcity events is relatively low initially, until plant has responded to exit signals;
- With the proposed security standard, it is unlikely that there will be that many weeks in which there are scarcity events. It is highly unlikely, for instance that 8 hours of lost load will occur through 8 different incidents in 8 different weeks. Given that demand, wind and outages from one hour to the next are significantly correlated, it is more likely that, if scarcity events do occur, they will be grouped into a small number of events in a small number of weeks.

5.3.13 The SEM Committee notes that the Stop-Loss limits only apply to uncovered difference payments, not all difference payments. For the incentive on a Capacity Provider to be removed after just two Billing Periods, the capacity would have to have been unavailable for some of all of the two events in those two weeks- which would be relatively unlikely for reliable plant.

5.3.14 One respondents argued that it was possible for typically reliable plant to be unavailable in one year for events across two weeks, and implied that it was appropriate for supposedly "reliable" plant to have its payments capped at a lower level. The SEM Committee recognises that this is true, but does not agree that this is a valid reason to cap their exposure at a lower level- payment should be on a results basis, rather than some other judgement of whether plant is reliable or not.

SEM Committee Decision

5.3.15 The SEM Committee has decided to set the Billing Period Stop-Loss Limit (as specified under d3.1.3(i) of the draft of the CMC issued for consultation as SEM-17-004a) at 50% of the Annual Stop-Loss Limit, i.e. 75% of the Annual Reliability Option Fee.

6 AUCTION PARAMETERS

6.1 INTRODUCTION

6.1.1 In CRM Decision 3 (SEM-16-039), the SEM Committee decided on a number of auction parameters, which need to be set. The key auction parameters and the process for setting them are as follows:

- **Auction Price Cap (APC)**. We proposed to set the Auction Price Cap as a multiple of Net CONE. The SEM Committee proposes to fix the multiple indefinitely in this CRM Parameters decision document, but will update the estimated Net CONE for each transitional auction, and for each subsequent T-4 and T-1 auction[11], and publish the updated Net CONE value prior to the start of the Qualification Window for each auction;
- **Existing Capacity Price Cap (ECPC).** This was previously referred to as the Uniform Price-taker Offer Cap. The Existing Capacity Price Cap will be set in €/kW, and vary by Capacity Year. The SEM Committee will set out its overall methodology for estimating this parameter in this CRM Parameters decision document, but will re-estimate and publish the value of the Existing Capacity Price Cap for each transitional auction, and for each subsequent T-4 and T-1 auction. The updated value will be published prior to the start of the Qualification Window for each auction. This CRM Parameters decision document sets out the value for the first transitional auction Existing Capacity Price Cap. Any existing capacity which considers that its Net Going Forward Costs are greater than the Existing Capacity Price Cap should apply for a higher Unit Specific Price Cap during the auction Qualification Window;
- **Demand curve parameters**. The demand curve parameters will be re-estimated for each auction, as they take into account Capacity Year specific factors such as the latest estimate for the Capacity Requirement for the Capacity Year in question, and any multi-year Reliability Options awarded in respect of that Capacity Year in prior auctions. This document sets out the indicative demand curve for the first transitional auction in respect of Capacity Delivery Year 2018/19, which is based on the demand forecast for 2021/22 and reflects the demand forecasts set out in 2017 Generation Capacity Statement[12].The demand curve published in this document will be the indicative demand curve that will be included in the Initial Auction Information Pack published by the TSOs in early July 2017. The actual demand curve to be used in the first transitional auction will be published in the Final Auction Information Pack published after the completion of the first transitional auction Qualification Window, and will be adjusted for the impact of any existing capacity which exercises its discretion not to bid but is still expected to make a capacity contribution[13][14]. It is anticipated that the Final Auction Information Pack for the first transitional auction will be published on 1st December 2017, in advance of the auction on 15th December 2017;
- **Locational parameters.** These parameters fall out of the work on CRM Locational Issues which had just been consulted upon (SEM-16-052) at the time of the parameters consultation being published. A Locational Issues Decision Paper has since been published

[11] Not every update will be a full re-estimate of all inputs into the calculation

[12] http://www.eirgridgroup.com/

[13] Applies to intermittent generation and non-firm transmission access generation

[14] Although the SEM Committee reserves the right to require the TSOs to re-estimate the Capacity Requirement, for instance in response to a materially updated demand forecast

(SEM-16-081) and the TSOs are currently developing a methodology for defining the zones and minimum MWs in each zone. This is expected to be consulted upon in mid-April 2017.

6.2 THE AUCTION PRICE CAP

Consultation Summary

6.2.1 In CRM Decision 3 (SEM-16-039), the SEM Committee stated that all auctions will employ an Auction Price Cap (APC), the APC being the maximum price Qualified Bidders may bid their Qualified Volume at, and is therefore the maximum price that the auction can clear at.

6.2.2 In practice, the Existing Capacity Price Cap will apply to all existing generators and interconnectors (with the exception of those who have applied and received a Unit Specific Price Cap), the Auction Price Cap will only be binding on new build capacity and existing DSUs.

6.2.3 The parameters consultation considered the principles which should apply in setting the Auction Price Cap in all I-SEM CRM auctions, and some specific issues which relate to how the solution will be applied practically for the first transitional auction. The Auction Price Cap parameter should be set at a level which balances:

- The risk that the Auction Price Cap is set at too low a level to incentivise new investment when it is needed, jeopardising **system security**; and
- The risk that the Auction Price Cap is set at too high a level, allowing market participants with market power to abuse their market power and drive up the auction clearing price, i.e. have negative effects with respect to **competition** and **efficiency objectives**.

6.2.4 In proposing an Auction Price Cap the parameters consultation paper considered international approaches, which are often expressed as a multiple of Net Cost of New Entry (Net CONE)- a calculation which is also used to set capacity payments within the SEM. The need for adjustments for outage assumptions, the introduction of an Administered Scarcity Price (ASP) combined with the Reliability Option and an adjustment from nameplate to de-rated capacity were all discussed within the parameters consultation paper.

6.2.5 The SEM Committee favoured setting the Auction Price Cap at 1.5 x Net CONE for the foreseeable future, since there is significantly more installed capacity than the Capacity Requirement, and since the experience of the SEM is that capacity providers have found a capacity payment of less than 1 x Net CONE adequate to cover their “missing money”. There is currently around 10,800 MW of installed capacity[15] according to the 2016 Generation Capacity

[15] Including a 500MW capacity credit for wind

Statement, whereas the 2016 Capacity Requirement is 7070MW. This means that the current level of capacity payments has resulted in significantly more capacity than required, despite each MW of capacity getting significantly less than Net CONE with an Annual Capacity Payment Sum designed for 7,070MW shared between 10,800MW. This multiple of 1.5 allows for a margin of error in the calculation of Net CONE.

6.2.6 An indicative Net CONE value of €77.81/de-rated kW/year for 2017 was presented within the parameters consultation paper. This compares with the SEM 2017 value of €71.44/kW of nameplate capacity, which relates to calendar year 2017[16]. The indicative value of €77.81/de-rated kW/year did not include any inflation indexing for the difference between calendar year 2017 (SEM capacity payments are based on calendar years, whereas I-SEM capacity payments are based on October to September capacity years). Furthermore, the CRM parameters consultation document was issued before the decision was made to delay go-live of the I-SEM until late May 2018. Following this decision, and the consequential decision to make the first transitional auction relate to Capacity Year 2018/19, it should be noted that the indicative value set out in the CRM parameters consultation paper will need to be appropriately adjusted from calendar year 2017 to Capacity Year 2018/19.

6.2.7 Therefore, if the Auction Price Cap is set at 1.5 x Net CONE, the indicative value of the Auction Price Cap would be €116.71/de-rated kW per annum, prior to adjustments to Capacity Year 2018/19. These figures were indicative and it will be necessary to update the indicative Net CONE, and hence the Auction Price Cap for *inter alia,* the following adjustments:

- Differences in Infra-Marginal Rent due to changes in the fuel cost of the BNE reference plant;
- Inflation which impact on fixed costs between now and 2018/19;
- Changes in ancillary service revenue between now and 2018/19.

6.2.8 Feedback was sought regarding the proposed adjustments to the Best New Entrant (BNE) calculation approach to determine the Net CONE value. Respondents were also asked if they agreed with the choice of a multiple of 1.5 x Net CONE in setting the Auction Price Cap.

Summary of consultation responses

6.2.9 We summarise the consultation responses under the following sub-headings:

- Are the proposed changes to the Net CONE calculation appropriate? And
- Is 1.5 x Net CONE an appropriate multiple for the APC

Summary of consultation responses: Are the proposed changes to Net CONE calculation appropriate?

[16] set out in the Final ACPS Decision 2017 (SEM-16-044)

6.2.10 A number of respondents agreed with the adjustments to the BNE calculation and recognised the importance of reflecting important changes arising in moving from SEM to I-SEM. Respondents cited changes including different IMR assumptions under the I-SEM, the Strike Price impact, accounting for de-rated capacity and the different generic forced outage rate used. One respondent stated that there is a need for this to be calculated in an open and transparent manner. One respondent stated that they felt it was in keeping with the current BNE calculation methodology. A number of respondents agreed with the Strike Price assumption of €500/MWh applying instead of the pool price cap in the revised BNE calculation. One of these respondents agreed with adding 4 hours of partial scarcity. A number of respondents stated that they agreed with the proposal to calculate all costs with respect to the de-rated capacity, describing it as a reasonable adjustment to include. One of these respondents described how the de-rating decisions should align with the BNE calculation as well as the conversion from nameplate to de-rated capacity.

6.2.11 A number of respondents raised differing concerns regarding the proposed adjustments to the BNE calculation:

- One respondent made a general point, stating they were concerned that some of the changes are moving away from the original process in an inconsistent way, and urged the RAs to reconsider their assumptions or provide supporting rationale and evidence where necessary.
- Another respondent stated that the proposed calculation of Net CONE makes arbitrary assumptions that are inconsistent with other assumptions and the realities of the market and have the effect of setting offer caps too low, unnecessarily adding to the administrative burden, and significantly increasing regulatory risk regarding cost recovery (for new and existing generators).
- One respondent stated that they would support a re-calculation of the BNE using transparent and objective parameters.
- One respondent did not agree with expressing Net CONE in de-rated terms (in the SEM Net CONE is not expressed in de-rated MW) because of the subsequent effect on the Auction Price Cap (Net CONE and the Auction Price Cap are about 5% higher in headline terms).

6.2.12 A number of respondents questioned the treatment of ASP and Partial ASP in the calculation of Infra-Marginal Rent, although there were differing views on what the appropriate approach should be:

- A number of respondents raised the issue of the use of 4 hours partial ASP. These respondents stated that using Partial ASP of 4 hours inflates the forecast of Infra-Marginal Rent (IMR) and depresses the value of Net CONE.
- Another respondent stated that the assumption around the 4-hours of Partial ASP events is too arbitrary and should not be applied to the RO payback calculation, suggesting that the 8-hour Full ASP assumption alone is enough to capture any and all expected RO payback periods.
- One respondent stated that the application of Partial ASP presupposes a decision on the ASP function under consultation within the parameters paper and it is not consistent with the theoretical IMR earnings for a new entrant plant. Another respondent stated that the proposition that there will be Partial ASP represents a very concerning misunderstanding of the security standard.

6.2.13 A number of respondents agreed with using an updated FOR, but did not agree with the value chosen, although again there were differing views on what the appropriate value should be:

- One respondent suggested that it should be 3.6% in line with the gas turbine technology category, i.e. that the proposed value of 5% is too high.
- Another respondent stated that they considered the assumed forced outage rate of 5% to be very low.
- Another respondent stated that the forced outages for energy and ancillary services should not be combined into a single value.
- Another respondent stated that they did not believe using the average forced outage rate for a cluster of units is an appropriate reference point for a very specific unit type.
- Another respondent stated that there is not necessarily appropriate to align the average FOR assumption for a BNE unit in the Net CONE calculation with assumptions used in de-rating TSOs' de-rating methodology, which is based on the marginal contribution of a unit to meeting the Capacity Requirement.
- Another respondent stated the BNE plant value of 95% is taken from the TSOs' indicative de-rating results, rather than their final de-rating results for the purpose of the CRM Parameters consultation document, implying that we should be using the final results, once finalised.

6.2.14 One respondent stated that Appendix C of the CRM Parameters consultation regarding the calculation of IMR does not take appropriate account of the IMR calculation. They argue that the decision to award additional Reliability Options to meet locational constraint will result in a reduced LoLE, and mean reduced IMR. This respondent also suggested that the mismatch between a Strike Price indexed to monthly fuel prices and more volatile actual spot fuel prices needs to be reflected in IMR calculation.

6.2.15 A number of respondents argued in favour of a range of different adjustments to the assumptions used to calculate the annualised investment costs of a Best New Entrant as result of the move from the SEM to the I-SEM:

- Some respondents stated that the WACC rate needs to be increased to reflect a view of higher risks in the I-SEM than the SEM.
- Some respondents suggested that the plant life assumption needs to be revised to 10 years from the current 20-year assumption following the decision to limit the Reliability Option fix price period for new plant to 10 years. A number of respondents stated that the higher working capital requirements under I-SEM need to be reflected in the Net CONE calculation.

6.2.16 One respondent asked if the proposed balancing offer regulations are in effect for the calculation of IMR. This respondent also suggested that adjustments for ancillary services in line with the overall DS3 budget also assumes no new entry or increased capability from existing providers and no performance penalties for the BNE, and also interactions between DS3 and the IMR if a commitment model is to be utilised under DS3. It was suggested by the respondent that all of these overlooked factors would suggest that the existing methodologies for calculating IMR and DS3 revenues will not be fit for purpose.

6.2.17 One respondent suggested an annual consultation process for setting Net CONE in each auction.

Summary of consultation responses: Is a multiple of 1.5 x net CONE appropriate?

6.2.18 A number of respondents stated that a multiple to 1.5 times Net CONE appears to be appropriate in the case of I-SEM and other international markets. One of these respondents stated how they believed the proposed price cap is investable but there are elements that will need to be reviewed following the introduction of I-SEM.

6.2.19 A number of other respondents did not agree with the proposed multiple of 1.5 x Net CONE for setting the Auction Price Cap, suggesting that an Auction Price Cap of a higher multiple of Net CONE is more appropriate. They described how the proposed multiple lies towards the lower end of international norms, and argued that some international regimes also apply a multiple to the Gross CONE, and that it would be prudent to take a multiple that was towards the top end of the international range for the I-SEM. A typical alternative multiple suggested was 2 x Net CONE. Representative comments from those requesting a higher multiple include:

- One respondent stated that a multiple of x1.5 will not cover all new entrant projects, and requested an opportunity for plants that can demonstrate Net Going Forward Costs in excess of the Auction Price Cap to bid in at that level.
- Another respondent stated that it is better to have a higher cap which does not create a barrier to entry, suggesting the multiple should be at upper end of range at x2 times.
- Another respondent suggested that with all the overlooked factors, the existing methodologies for Net CONE is not fit-for-purpose, and therefore, a higher multiple should be used for the Auction Price Cap, e.g. 200% of the BNE price.
- Other respondents argued that more analysis/justification of the cap is necessary. One respondent stated that little evidence is set out for the decision of 1.5 as the multiplier for net CONE other than typical market convention. Another respondent stated they would like to see a methodology/process introduced as part of this process which clearly outlines how the multiple for setting the Auction Price Cap is set. This respondent described how at today's capacity margin levels the appropriate price cap may be 1.5x Net CONE, but as the capacity margin becomes tighter, there could be a sliding scale moving from 1.5x to 2.0x Net CONE. Another respondent stated that the multiple value should be subject to review as discussed in the consultation.

SEM Committee Response: Are the proposed changes to Net CONE calculation appropriate?

6.2.20 The SEM Committee thinks that the BNE Net CONE is determined in as transparent and objective manner as is possible. Where changes were proposed to the SEM Net CONE calculation methodology, the key changes and assumptions were set out in detail in the CRM Parameters consultation document (SEM-16-073). Elsewhere, the methodology / assumptions remain unchanged from the SEM Net CONE calculation approach, which has been spelt out in detail in previous SEM document (see for instance SEM-16-044, the 2017 Annual Capacity Payment Sum decision paper).

6.2.21 The SEM Committee recognises that respondents have made a number of detailed points about the detailed values of assumptions used, and we discuss these further below. However, in general, we note that whilst there is always room for debate about the precise value of certain assumptions to be used, we allow for 50% uncertainty in Net CONE in setting the Auction Price Cap, which is equivalent to nearly €40/de-rated kW/ yr. This should be sufficient to absorb all the uncertainty given that:

- We note that there is zero percent uncertainty margin in Net CONE estimate in the SEM, where Net CONE governs the payments that all Capacity Providers receive; and
- The estimate of Net CONE is not an absolute limit on the bids of existing generators, since although the Existing Capacity Price Cap (ECPC) is a multiple of Net CONE, existing generators can apply for a higher bid limit, which is set independent of Net CONE.

6.2.22 Of the assumptions that go into the calculation of Net CONE, those relating to the annualised fixed cost (i.e. Gross CONE) are the most material, since Gross CONE is around 120% of Net CONE, whilst IMR is less than 5% and ancillary service income around 15%. Therefore, we discuss the assumptions with respect to the annualised fixed costs of investment first, before focussing on those related to IMR and ancillary service income.

6.2.23 It has been suggested that it is appropriate to review a number of the assumptions that go into calculating the annualised fixed cost of a BNE plant, including the Weighted Average Cost of Capital (WACC), the plant life assumption and the amount of working capital employed. In this context, a number of respondents argued that the risk to market participants will be higher in the I-SEM than in the SEM, and the WACC should be adjusted upwards as a result. However, we note that none of the respondents provided a view on how much higher WACC should be, with accompanying justification.

6.2.24 The SEM Committee believes that it remains to be seen as to whether risk will be higher under I-SEM than the SEM, and if so to what extent. It is premature to try to quantify this risk at the moment. In particular, it is not clear that it will be particularly risky for new peaking plant, if it derives the bulk of its revenue /profit from long term fixed capacity payments and ancillary service payments, and has relatively little exposure to energy balancing since it runs infrequently.

6.2.25 Nevertheless, the SEM Committee has run a sensitivity test to assess the impact on Net CONE if the GB WACC was used, instead of the current SEM WACC. Arguably the I-SEM design, with Day-Ahead, Intra-Day and Balancing energy markets, and a competitive CRM is closer to the design of the GB market than the SEM market. The GB Net CONE is based on a WACC of 7.5%

pre-tax real[17], which is based on a study[18] commissioned by the UK Department of Energy and Climate Change (DECC) in 2013. By contrast, the SEM 2016 WACC analysis which was conducted in 2015 (see SEM-15-059) estimated an average WACC of 5.17% pre-tax real. In part the difference between the GB WACC and the SEM 2016 WACC may be one of timing. In 2016, the SEM WACC was reduced by 1.4% from 6.6% pre-tax real, to reflect the decline in the risk-free rate and capital costs more generally between 2013 and 2016- a change not reflected in the GB BNE Net CONE. However, even if the I-SEM WACC were to increase to 7.5% from currently assumed WACC of 5.17% pre-tax real, our analysis suggests that this would only cause a 13% increase in annualised Gross CONE and a 15% increase in Net CONE, well within the 50% estimation uncertainty provided for in the Auction Price Cap.

6.2.26 The SEM Committee does not agree that it is appropriate to cut the plant life assumption from 20 years to 10 years, to reflect that the fact that the maximum Reliability Option price fix length is 10 years. It is worth making a number of observations in this regard:

- Just because the Reliability Option only guarantees a new build plant its option price offer for up to 10 years, it does not mean that the plant will not have any residual value after 10 years. From year 11 onwards, the plant may continue to earn Infra-Marginal Rent and ancillary service income in those markets, and may continue to bid into capacity market auctions. Its ability to be competitive in those markets from year 11 onwards will be determined by a number of factors, such as the rate of technological obsolescence, which are largely, if not totally independent, of the I-SEM design;
- By fixing the capacity payment for 10 years for new build plant, the I-SEM is providing the Capacity Provider with a much longer price guarantee than in the SEM. In the SEM, the price can vary from year to year, based upon re-assessment of a number of key assumptions which go into the calculation of the annualised fixed cost, the Infra-Marginal Rent and ancillary service income. Furthermore, capacity provider revenue in the SEM Capacity Payments Mechanism can be diluted from year to year when capacity installed exceeds the Capacity Requirement, whereas a Capacity Provider with an I-SEM Reliability Option is protected from this risk for up to 10 years;
- Other markets, such as US markets which have shorter fixed price periods (typically 5 to 7 years maximum) do not adjust the economic life assumption that underpins their Net CONE commensurately either.

6.2.27 It is also not yet clear how much working capital will be required of generators in the I-SEM, and the extent to which it exceeds that of SEM generators (or other capacity providers). There is no reason to assume for instance, that there will be any change to a key source of working capital.

6.2.28 Given the results of the above sensitivity analysis, and the 50% uncertainty margin built into the Auction Price Cap, the SEM Committee has decided that it is not necessary, at this point in time, to conduct an extensive review of the WACC, or other assumptions that go into

[17] We are aware that the GB Net CONE is based on the cost of capital for a CCGT, but the study used to determine the GB WACC also estimated the same cost of capital for an OCGT

[18] DECC Electricity Generation Costs 2013 (Table 16)

calculating the annualised fixed cost. It may be more appropriate to review the WACC once the I-SEM is operational and there is a stronger evidence base for re-assessing the level of risk and/or for the first T-4 auction, where more significant new entry is expected.

6.2.29 Inevitably, there are some areas where assumptions need to be made which govern the estimates of Infra-Marginal Rent and ancillary Service income (e.g. number of Full and Partial ASP hours, the Partial ASP when Partial ASP applies, Forced Outage Rates). For this reason we have set out our rationale for the chosen assumptions in the consultation document. Whist there are a number of comments on this approach there is no consensus around alternative assumptions.

6.2.30 We have conducted sensitivity analysis on these assumptions, and note that the variation in these assumptions has a relative small impact on Net CONE, not least because they account for only a 20% reduction in Net CONE below Gross CONE. This is well within the 50% estimation uncertainty provided for by setting the Auction Price Cap at 1.5 x Net CONE. In particular, we estimate that:

- Total IMR for the BNE unit in 2018/19 is only 4.5% of Net CONE. Therefore, even if we used the most conservative assumptions possible for Full and Partial ASP and Forced Outage Rates, so that zero IMR is earned, this would only lead to a 5% increase in the Net CONE estimate.
- Whilst ancillary service income is forecast to grow to around 15% of BNE Net CONE by CY2018/19 due to the growth in the DS3 budget, a change in the Forced Outage Rate assumption from, say 5% to say 10% would have less than a 1% increase in the Net CONE estimate.

6.2.31 We propose to keep with a Forced Outage Rate (FOR) of 5% for BNE plant. We note the point made by one respondent that there is not a direct link between the average FOR used in the BNE calculation and the marginal capacity contribution of a unit which is reflected in the de-rating factor. The SEM Committee notes that the marginal de-rating approach explains how a 100MW unit and a 500MW unit with the same FORs can have different de-rating factors. However, it appears inconsistent that a plant which supposedly has a 5.91% FOR (used in the SEM IMR) calculation, can contribute more than a (100% - 5.91%) marginal capacity contribution. If it has a 5.91% outage rate at times of scarcity (the implication of the IMR calculation) then at most it can contribute 94.09% to the marginal capacity contribution.

6.2.32 The SEM Committee does not agree that an adjustment needs to be made to the IMR calculation to reflect the fact that the Reliability Option Strike Price is based on a monthly fuel price, whereas generators may buy fuel in daily spot markets. Whilst it is true that some peaking gas generators will buy fuel in spot markets rather than month ahead markets, the SEM committee does not agree that this merits a material adjustment, for a number of reasons:

- As discussed above, IMR is less than 5% of Net CONE, well within the 50% tolerance built into the Auction Price Cap;
- It is likely that the DSU Floor price will set the Strike Price for most of the time;
- Oil generators which are generally more expensive than gas generators buy oil products in markets that are priced in months.

6.2.33 The SEM Committee does not agree with the respondent who effectively argued that it is not appropriate to express the Net CONE in terms of de-rated kW because this results in a higher €/kW number. Generally[19], a Capacity Provider can only obtain a Reliability Option on its de-rated capacity, and this should be reflected in the Net CONE number. The Capacity Requirement is also expressed in de-rated MWs, and is lower as a result, so should have a broadly offsetting impact on consumer bills.

6.2.34 The SEM Committee has therefore decided to maintain the BNE Net CONE approach / assumptions set out in the CRM Parameters consultation, although the marginal de-rating factor for the BNE reference plant may change from 95% as a result of ongoing work by the TSOs on de-rating factors. In particular, the TSOs are in the process of re-estimating de-rating curves using their new ADCAL model, and de-rating factors are expected to change as a result of the improved approach to scheduling outages in the ADCAL model, plus some various other data updates. Changing the de-rating factor will not change the Net CONE in €/nameplate kW, but will have an impact on the Net CONE expressed in €/de-rated kW, and hence have an impact on the Auction Price Cap (APC) and the Existing Capacity Price Cap (ECPC). For instance, if the marginal de-rating factor for the BNE reference plant changes from 95% to 90%, Net CONE in €/de-rated kW will increase by 95%/90% = 5.56%.

6.2.35 As discussed in Section 7, the New Capacity Investment Rate Threshold (NCIRT) is a function of gross BNE investment cost[20], rather than Net CONE, but a change in the de-rating factor will also have the same proportionate impact on the (NCIRT).

SEM Committee's Indicative Net CONE Calculation

6.2.36 Notwithstanding the fact that we anticipate that Net CONE for the first transitional auction will change as a result of revised BNE estimates of the marginal de-ratings factors, we have provided an indicative estimate of Net CONE for 2018/19 to illustrate the calculation below.

Summary calculation of Net CONE

6.2.37 The SEM Committee has re-estimated the indicative Net CONE for CY 2018/19, consistent with the assumptions set out in the CRM Parameters consultation, but taking the following account of the fact that parameters for the first transitional auction will now be for CY2018/19:

- Annualised investment cost will be inflation adjusted to CY2018/19 values by adjusting the annualised fixed cost for 2017 published in SEM-16-044 by 4.6% (the latest UK RPI figure of 2.6% compounded for 1.75 years);
- Grossing up the assumed BNE ancillary service revenue by 148% to account for the expected increase in DS3 budget between Calendar Year 2017 and Capacity year 2018/19. The SEM Committee notes that some respondents questioned whether it is appropriate to assume that a BNE plant would earn higher ancillary service revenue or whether

[19] With the exception of a Reliability Option acquired at short notice in the secondary market via the secondary trading platform. Note that the secondary trading platform is unlikely to be available on Day of the I-SEM (see Section 8.2).
[20] not annualised, and not net of infra-marginal rent and not annualised

increased budgets would be spread over a wider set of providers. However, the SEM Committee does not believe there is any evidence to support a different approach to that outlined above.

6.2.38 As shown in Table 2, the BNE Gross CONE (Annualised Fixed Cost) published in SEM-16-044 was €85.08/nameplate kW.

6.2.39 RPI data for Jan 2017 (published 13 February 2017) shows an inflation increase of 2.6%[21]. There are 1.75 years between the start of SEM Capacity Payment Mechanism year 2017 (January 2017) to I-SEM Capacity Year 2018/19 (October 2018), so we have compounded the inflation rate of 2.6% by 1.75 to an inflation adjustment of 4.6%, so the revised BNE Gross CONE for CY2018/19 is €88.99/ nameplate KW.

6.2.40 The estimated infra-marginal rent for a BNE unit is €3.28/nameplate kW, and the estimated ancillary service income is €10.84/nameplate kW- see later further explanation below. Therefore, the CY2018/19 BNE Net CONE is €74.88/nameplate kW. The provisional de-rating factor for the reference BNE unit (an OCGT of 195 MW nameplate capacity) is 95%, **so the *indicative* value for the CY2018/19 BNE Net CONE is €78.82/de-rated kW**.

Table 2: Summary Net CONE calculation

Item	Amount	Units
SEM 2017 BNE Net CONE	71.45	€/nameplate kW
SEM 2017 BNE Annualised Fixed Cost	85.08	€/nameplate kW
Annual inflation rate	2.60%	
Compounded inflation to CY 2018/19	4.59%	
I-SEM 2018 BNE Annualised Fixed Cost	88.99	€/nameplate kW
Infra-marginal rent	3.28	€/nameplate kW
Ancillary services	10.84	€/nameplate kW
I-SEM 2018/19 BNE Net CONE	74.88	€/nameplate kW
BNE de-rating factor	95.00%	
I-SEM 2018/19 BNE Net CONE	78.82	€/derated kW

Infra-marginal rent calculation

[21] Based on UK RPI all items inflation index CZBH, source dataset MM23. See: https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/czbh/mm23

6.2.41 The infra-marginal rent for the BNE plant for 2018/19 takes account of the introduction of Administrative Scarcity Pricing (ASP), but assumes that the BNE plant's infra-marginal rent is capped at the Reliability Option Strike Price on the portion of its volume that is covered by the Reliability Option.

6.2.42 The key input assumptions into the calculation (in addition/ instead of the assumptions previously made in calculating the 2017 SEM BNE infra-marginal rent) are as follows:

- The de-rating factor for the BNE plant is 95%, so 95% of the BNE plant's nameplate MW is covered by a Reliability Option, and the remaining 5% of its capacity can earn the full ASP;
- An assumption that the incremental fuel cost bid of the BNE plant is €212.58/MWh. The bid price is based on the average bids of distillate fired plants from Within Day data from the Single Electricity Market Operator (SEMO) averaged over the period 20-24 February 2017;
- The forced outage rate of the BNE plant is 5%;
- There are 8 hours of Full Administrative Scarcity Pricing, during which time the energy price is €3000/MWh, and 4 hours of partial ASP during which the partial ASP is half the full ASP, i.e. €1,500/MW- which is consistent with Option 1 for the partial ASP function, as decided in Section 3.

6.2.43 The resulting calculation of infra-marginal rent per nameplate MW is shown in Table 3 below, and illustrates that the estimated annual infra-marginal rent is €3,276 per nameplate MW per year, i.e. €3.28 per nameplate kW.

Table 3: Calculation of 2018/19 I-SEM BNE infra-marginal rent

I-SEM ASP scenario	Outage Scenario	Capacity component	I-SEM IMR (€/nameplate MW/yr)
Full (8 hours @ €3,000/MWh)	Forced outage (5% of time)	De-rated (5% of capacity)	0
		Covered by RO (95% of capacity)	- 950.00
	Running (95% of time)	De-rated (5% of capacity)	1,059.22
		Covered by RO (95% of capacity)	2,075.17
Partial ASP (4 hours @ €1,500/MWh)	Forced outage (5% of time)	De-rated (5% of capacity)	-
		Covered by RO (95% of capacity)	- 190.00
	Running (95% of time)	De-rated (5% of capacity)	244.61
		Covered by RO (95% of capacity)	1,037.59
Total (€/MW p.a.)			3,276.59

Ancillary services income calculation

6.2.44 In SEM-16-044 (Final ACPS Decision 2017), the SEM Committee published the estimate of BNE ancillary service income as €7.34/nameplate MW. The projected increase in the DS3 System Services budgets is shown in Table 4 below.

Table 4: Projected increase in DS3 System Services budget

Year	2015/16	2016/17	2017/18	2018/19

DS 3 System Services Budget	€54.0m	€75.0m	€115.0m	€155.0m

6.2.45 We have estimated an approximate "budget" of €105m for Calendar Year 2017[22]. We have therefore applied a gross up factor of (155/105= 1.476) to estimate 2018/19 BNE ancillary service income as €10.84/nameplate kW/year.

Next steps

6.2.46 The RAs will update the calculation of Net CONE prior to the June 2017 SEM Committee taking account of:

- Changes to the BNE reference plant de-rating factor; and
- The latest annual UK RPI all items inflation figure.

6.2.47 The calculation will otherwise use the same approach and assumptions as the indicative calculation above. The value approved by the June SEM Committee will be the final 2018/19 Net CONE, and hence determine the consequential values of APC and ECPC for the first transitional auction.

6.2.48 This Net CONE value will apply for the first transitional auction only. The SEM Committee will conduct a full review of the assumptions appropriate for the CY2022/23 T-4 auction (which is likely to be the next auction), probably in Q1 2018 after the first auction, but in advance of the requirement to publish the Initial Auction Information Pack for the CY2022/23 auction. The results of that review will also inform the setting of the Net CONE for the other transitional auctions.

SEM Committee Response: Why a multiple of 1.5 x net CONE is appropriate

6.2.49 The SEM Committee believes that the multiple of 1.5 x Net CONE is appropriate for the first transitional auction. A 1.5 multiple is adequate to cover uncertainty over certain assumptions that go into the calculation of Gross and Net CONE. These include the WACC, the number of hours of full and partial ASP, and the potential uncertainty around ancillary service revenue.

6.2.50 The SEM Committee notes that Capacity Providers would prefer a higher multiple towards the higher end of international norms, but the SEM Committee sees no justification for such a multiple, particularly in the current market, where installed capacity significantly exceeds the Capacity Requirement. The fact that Capacity Providers are currently receiving an average of less than Net CONE (since a SEM Capacity Payment pot of Capacity Requirement x Net CONE is spread over significant more capacity) is further evidence to support the view that there is no reason to raise the multiple above 1.5. Raising the multiple further would only increase the

[22] 25% of 2016/17 budget and 75% of 2017/18 budget

possibility of Capacity Providers exerting market power. This is the justification for being at the lower end of international norms.

6.2.51 One respondent expressed concern that not all new build would be accommodated within a price cap of 1.5 x Net CONE, and sought the opportunity to put in a higher bid submission based on higher Net Going Forward Costs. The SEM committee does not think that this is appropriate. The I-SEM CRM is designed to incentivise efficient capacity. Efficient capacity may be capacity which has a low fixed cost- such as the reference Best New Entrant plant, or could have higher gross investment costs, but is more efficient (so able to earn higher offsetting Infra-Marginal Rent) or more flexible (so able to earn higher offsetting ancillary income). Thus a plant may have gross investment costs of more than 150% of the Best New Entrant plant, but would need more Infra-Marginal Rent or more ancillary service income per de-rated kW to be competitive in the I-SEM. Any plant which is not able to compete within 150% of Net CONE is unlikely to be successful on a sustainable basis in a competitive I-SEM CRM, and there is no value to the consumer in such uncompetitive plant being facilitated by the SEM Committee. Allowing such plant may only facilitate the exercise of market power- for instance, if some potential Capacity Providers have market power due to ownership of a limited set of sites for new build.

6.2.52 Overall, the SEM Committee thinks that international precedent provides a reasonable basis for setting the Auction Price Cap at 1.5 x Net CONE, and no convincing evidence was presented that using a 1.5 multiple of Net CONE will interfere with the efficient operation of the energy markets as a whole, particularly under current market conditions. **The SEM Committee therefore intends to set the Auction Price Cap at 1.5 x Net CONE for the first transitional auction. However, the SEM Committee may choose to review the Auction Price Cap multiple (as well as the value of Net CONE) in advance of future auctions**.

SEM Committee Decision

6.2.53 The SEM Committee has decided to:

- Adopt the proposed changes to the Net CONE calculation set out in the consultation document (SEM-16-073). The indicative value for Net CONE is €78.82/de-rated kW;
- Set the Auction Price Cap for the first transitional auction at 1.5 x Net CONE. The indicative value for the Auction Price Cap is €118.23/de-rated kW;
- Finalise the Net CONE (and hence APC and ECPC) for the first transitional auction for changes to the BNE reference plant de-rating factor and the latest inflation value for approval by the June SEM committee meeting for inclusion in the Initial Auction Information Pack in early July;
- Review the key assumptions in setting Net CONE before the first T-4 auction, which will be for capacity delivery in CY2022/23.

6.3 ECPC, USPCS AND NGFCS

Summary of consultation

6.3.1 In addition to the Auction Price Cap, in CRM Decision 3 (SEM-16-039), the SEM Committee decided to introduce the following bid limits which should apply to existing generators:

- A Uniform (i.e. non-technology specific) Price-taker Offer Cap. This parameter has been termed the Existing Capacity Price Cap (ECPC) in the Capacity Market Code drafting. All Existing[23] Generators and interconnectors will be required to bid their full Qualified Volume into the transitional auctions and the T-4 auctions at a price no higher than the Existing Capacity Price Cap (specified in €/kW or £/kW), unless they apply for higher Unit Specific Price Caps as set out below, or submit an Opt-Out Notification on the grounds that they are going to close before the end of the relevant Capacity Year. DSUs are not subject to the Existing Capacity Price Cap, and may bid up to the Auction Price Cap;
- Right to apply for higher Unit Specific Price Caps (USPC): Where an existing generation or interconnector Capacity Market Unit (CMU) is able to evidence the fact that it has higher unavoidable Net Going Forward Costs (NGFCs) than the Existing Capacity Price Cap, it will be able to apply to be allowed to submit a higher Unit Specific Price Cap– up to the level of the unit's individual Net Going Forward Costs.

6.3.2 The CRM Locational Issues consultation (SEM-16-052) also considered the option of implementing a unit specific bid limit for any plant required for local security of supply reasons.

6.3.3 It was anticipated that the Existing Capacity Price Cap will be set at a level which allows the vast majority of existing capacity to bid its Net Going Forward Costs into the auction, without having to apply for a higher unit specific bid limit.

6.3.4 To set the Existing Capacity Price Cap at an appropriate level, the SEM Committee needs to:

- Define the methodology and approach for estimating Net Going Forward Costs (NGFC);
- Estimate the range of Net Going Forward Costs of existing plant; and
- Consider what plant exit should be assumed, if any, in the calculation of infra-marginal rent (a component of Net Going Forward Costs) as a result of the move to the volume based I-SEM CRM.

6.3.5 The parameters consultation set out the rationale for considering defining Net Going Forward Costs for a capacity provider as:

Max [(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets),0] + Expected Reliability Option difference payments

[23] Generators which meet the criteria for new build generation will not be subject to the Existing Capacity Price Cap and may bid at a price up to the Auction Price Cap

6.3.6 Respondents were asked if they agreed with the above proposed methodology for estimating a generator's Net Going Forward Costs.

6.3.7 With regard to the process and data to set the Existing Capacity Price Cap, the SEM Committee intends to use the current SEM Generator Financial Reporting data as the basis for estimating fixed operating costs[24]. The SEM Generator Financial reporting data contains a unit level historical breakdown of the costs of generators into Fuel Operating Costs, and Non-Fuel Operating Costs. Whilst the fuel / non-fuel operating cost breakdown may be similar to the fixed/ variable breakdown, there may be some adjustments that need to be made to the Generator Financial Returns to align the reported numbers to the fixed/variable definition, and the SEM Committee sought feedback on what adjustments are appropriate.

6.3.8 The SEM Committee may also undertake some adjustments to reported data, where for instance, it is of the view that cost allocations between units are not appropriate, or that the reported results are not consistent with efficient operation of the assets in question.

6.3.9 In setting the Existing Capacity Price Cap there will be a need to:

- Undertake PLEXOS modelling of I-SEM energy revenues for the relevant Capacity Year, using appropriate fuel and carbon forward price curves for the relevant Capacity Year;
- Project ancillary service revenues, taking appropriate account of the increase in the DS3 budget for each relevant year; and
- Make relevant projections of change in costs, such as inflation and known changes in TUoS charges, etc.

[24] See Generator Financial Reporting in the SEM, a SEM Committee Decision Paper, 2nd May 2012 (SEM-12-027)

6.3.10 For the parameters consultation, the Regulatory Authorities collated and assessed historical data to produce an average Non-Fuel Operating Costs (NFOC) by fuel category which was published n the parameters consultation paper. The need for adjustments to these NFOC and international benchmarks of fixed operating and maintenance costs were also detailed.

6.3.11 Respondents were asked if they considered the Non-Fuel Operating Costs reported by generators to the RAs as part of the SEM Generator Financial Reporting are a good proxy for the Fixed Operating and Maintenance costs that a capacity provider may need to recover via the I-SEM CRM, or if the NFOC contain material variable cost which can be recovered via the energy/ancillary services market? If the latter, how big an adjustment should the SEM Committee make to exclude any variable elements of the NFOC from NGFCs included in the Existing Capacity Price Cap? Feedback was also welcomed as to why SEM costs are higher than international benchmarks, and whether there is scope for generators to cut fixed operating costs going forward, or whether they are an unavoidable consequence of the age of SEM plant. If there is material scope to cut fixed operating and maintenance costs should this be reflected in the Existing Capacity Price Cap.

6.3.12 Within the parameters consultation the SEM Committee proposed setting the Existing Capacity Price Cap at around 0.5 x Net CONE. The rationale for proposing the Existing Capacity Price Cap at this level is that:

- If set at this level, we estimate that the vast majority of plant required to meet the Capacity Requirement could bid at its NGFC without needing to apply for a unit specific bid limit; and
- It is consistent with relevant international benchmarks.

6.3.13 Respondents were asked if they agreed with the proposed approach of setting the Existing Capacity Price Cap at 0.5 x Net CONE or to detail their alternative approach and rationale.

6.3.14 The SEM Committee hopes that competition from capacity providers will reduce fixed operating costs below current levels over time. However, given the tight timescale and the practical difficulties in establishing achievable fixed cost efficiency savings, the SEM Committee is not inclined to factor in significant potential savings into the Existing Capacity Price Cap for the first transitional auction. However, where a generator bids for a higher unit specific cap, the SEM Committee does not preclude requiring the generator in question to bid at a level consistent with efficiency savings.

Summary of consultation responses

6.3.15 Given the wide range of issues raised in the consultation, and their importance, we have received a high volume of responses from the industry (predominantly from Capacity Providers) to the issues surrounding the determination of Net Going Forward Costs (NGFCs), Unit Specific Price Caps (USPCs) and the Existing Capacity Price Cap (ECPC).

6.3.16 Some respondents agreed with the proposed methodology to determine Net Going Forward Costs, but other respondents stated they have a number of concerns about the proposed approach. Given the volume and range of response, we summarise the responses under the following headings:

- **Treatment of sunk costs**: There was strong push back from industry, on the exclusion of sunk costs from Net Going Forward Costs, Unit Specific Price Caps, and by extension the Existing Capacity Price Cap. Sunk costs could include depreciation of existing generation assets, interest payments on debt, repayment of debt and return on equity. It was argued that the proposals which exclude sunk costs from NGFCs, in conjunction with controls imposed in the energy market, will deny generators the chance to recover their total costs;
- **Incorporating scope for efficiency gains in bid controls**. A number of generators commented on our review of SEM generator costs and international benchmarks. They set out a range of explanations for why SEM generators' costs are generally higher than international benchmarks, and argued that competition, rather than regulation should be used to drive out efficiency savings;
- Other concerns about NGFC methodology / process / data including:
  - **Using Non-Fuel Operating Costs (NFOCs) as proxy for Fixed Operating Costs (FOCs) in the NGFC formula.** Whilst some respondents agreed with our proposed approach of using NFOCs as a proxy for FOCs, a number of respondents had a range of detailed comments on this proposed approach, and on our discussion of whether it is appropriate to make adjustments to take account of variable Non-Fuel Operating Costs that are recovered via the energy market;
  - **Treatment of unavoidable investment costs**. There were arguments that required future investment to keep existing plant open, or to upgrade its capacity were not adequately provided for in the bid controls. It was argued that their exclusion from the NGFC formula, along with our decision not to have a specific refurbishment category eligible for multi-year Reliability Options could discourage efficient investment in plant refurbishment/upgrades and discriminates in favour of new build plant; and
  - A range of other issues related to the NGFC / USPC methodology, process and data;
- **The overall level of the ECPC**. Some respondents argued that the ECPC should be set higher than 0.5 x Net CONE.

Treatment of sunk costs

6.3.17 There was strong push back from existing generators to the proposed treatment of sunk costs. In particular:

- Setting ECPC at 0.5 x Net CONE would preclude a number of existing generators from recovering their sunk costs if required to bid at that level; and
- The NGFC methodology does not allow existing generators to reflect their sunk costs in USPC applications.

6.3.18 The main criticisms of the SEM Committee's proposed treatment of sunk costs can be summarised as follows:

- The SEM Committee's unduly restrictive approach to ECPC/USPC/NGFC is flawed and will harm competition. It was argued that, "Competitive market pricing requires flexibility to price above variable costs so that the competitive process can flourish. Ruling out such pricing would hinder the competitive process and deny generators a legitimate means to recover their costs. However, this is precisely what the Regulatory Authorities are proposing to do in I-SEM, which is contrary to their statutory duty to promote competition". It was further argued that the SEM Committee have, "*a flawed interpretation of the theoretical ideal of perfect competition, which is not even applicable to sectors with long run, irreversible investments", and this lead us to believe that "prices that deviate from strict definitions of short run marginal costs can be consistent with competitive behaviour*".

- The SEM Committee is denying generators the opportunity to recover their total costs". It was argued that the whole package of market rules must offer all market participants the opportunity to recover their total costs – including sunk costs, operating expenses and the cost of capital. It was argued that the combination of SRMC (of supplying energy) based energy market bidding rules and SRMC (of supplying capacity) based CRM bid caps mean that generators are denied the opportunity to recover their total costs. It was further argued that:
  - The Regulatory Authorities' approach does not comply with their statutory obligation to have due regard to the need to ensure that generators are capable of financing their licensed activities, or promoting competition;
  - The SEM Committee's denial of total costs is unjustified;
  - This particularly affects constrained-on generators, who will be subject to SRMC based price regulation in the energy market and denied the chance to recover sunk costs in the capacity market;
  - "Disallowing sunk costs will discourage future investment. The CRM Parameters Consultation paper only denies the need to recover the sunk costs of "existing investors", as if such costs formed a special category because they were incurred before the current date. However, for investors in long-lived assets that operate under a permanent (albeit evolving) regulatory regime, there is no such thing as a special date, before which "past" costs can be ignored whilst "future" costs are avoidable (and must be remunerated). A regulatory policy of disallowing, or even just ignoring, sunk costs will inevitably discourage future investment".
  - "Disallowing sunk costs will also discourage efficient plant upgrades. In order to remain available, existing generators will have to invest in maintenance and in refurbishments, the benefits of which last for several years. If such investment reaches the New Capacity Investment Rate Threshold, it would be eligible for a long-term capacity contract, but in our view, it will be impossible to reach the high threshold as currently defined".
  - Our proposals are inconsistent with State aid considerations. It was argued that our proposals, "are inconsistent with the part of the Energy State Aid Guidelines (EEAG) that require that in order for aid to be compatible, the scheme must "improve the functioning of a secure, affordable and sustainable energy market" (paragraph 49) and "not undermine investment decisions on generation which preceded the measure" (paragraph 233). It was further argued that a measure which denies overall cost recovery to existing capacity and restricts existing capacity to only recovering recurrent costs is inconsistent with both these requirements and discriminates without valid justification between existing and new capacity."
  - Greater flexibility is required. It was argued that "*by denying any prospect of total cost recovery, the I-SEM will destroy any incentive to invest in keeping capacity available, or in building new capacity – particularly within the constrained areas where capacity is most valuable to the system. Unless the SEM Committee gives immediate consideration to this problem, and provides relief from it by lifting or slackening some of the restrictions, the I-SEM will soon be in crisis with the prospect*

of further significant regulatory intervention being required to ensure security of supply."

– "*The SEM Committee cannot rely on "international best practice" to justify this approach, since there is no system in the world that aims (or could ever aim) to foster competition and security of supply with the combination of measures currently proposed for the I SEM's markets in capacity and energy"*.

Incorporating efficiency savings within bid controls

6.3.19 Existing generators objected to the proposal to incorporate the efficiency savings into bid controls for existing generators. They:

- Provided a range of different explanations for why generator fixed costs may be higher in the SEM than in other countries; and
- Argued that competition in the CRM, rather than regulation should be allowed to drive out any efficiency savings.

6.3.20 A number of respondents set out different possible reasons for the higher costs of SEM generators compared to international benchmarks. These included:

- Gas capacity and transportation costs. One respondent described analysis that shows a power plant in Ireland has somewhere in the range of three to seven times the costs for gas transportation capacity costs compared to a GB plant;
- Small unit sizes and the lack of economies of scale;
- Age of plant. A number of respondents stated that they did not believe that existing SEM generators have material scope to cut fixed operating and maintenance costs owing to the old age of existing plant (and inherent design of older multi-unit power stations) and the inherent increased operating and maintenance costs *vis a vis* newer plant. One respondent suggested that the only one of the significant costs that generators could potentially reduce is O&M contracts.
- Security of supply commitments;
- Higher renewables penetration and subsequent operating modes of units (more intermittent operation);
- DS3 costs operating in a limited connected island electricity network;
- Requirement for dual fuelling;
- Different environmental protection commitments;
- Other differences in regulatory conditions;
- Wage rates; and
- Taxes.

6.3.21 Exchange rate fluctuations were also cited as possibly causing costs incurred at similar levels in one year to appear different in later years. Also, it was argued that accounting standards vary by jurisdiction, and not all accounts may be prepared according to the same standards (or IFRS).

6.3.22 One respondent stated that it is not possible to comment on relative costs without conducting a detailed analysis due to wide variations in interpretation and cost categorisation.

6.3.23 One respondent described how they believe that it is up to the capacity market to force generators to find alternative ways to lower their costs. The respondent stated how it should not be something for the RAs to force on the basis of international precedent. Notwithstanding the above, it was suggested that costs incurred by generators in Ireland can differ greatly from their counterparts in the UK.

6.3.24 One respondent described how introducing concepts like efficiency savings or disallowable costs is entirely inappropriate, as generation assets are not regulated assets, decisions on efficient costs would effectively place some responsibility for operational decision making on the RAs, a tighter cap for existing capacity will only increase the number of exceptions for the RAs to review, and bias the auction in favour of more expensive new build capacity.

6.3.25 However, one respondent stated that the most likely explanation appears to be a lack of competition, and suggested driving an incentive to minimize these costs and that this could be corrected by introducing a lower Existing Capacity Price Cap.

Using NFOCs as proxy for FOCs in the NGFC estimates

6.3.26 There was a range of views on the suitability of using Non-Fuel Operating Costs (NFOCs), as reported in Generator Financial reporting, as a proxy for Fixed Operating Costs (FOCs) in the Net Going Forward Cost (NGFC) calculation. Whilst a number of respondents pointed to a range of different issues, few provided concrete suggestions as to alternative data sources, or how to make appropriate adjustments.

6.3.27 One respondent agreed that the costs reported by generators should be used as a proxy for determining the NGFCs for setting the Existing Capacity Price Cap, but also suggested that the RAs should share the dissemination of data with parties on a bi-lateral basis when calculating the NGFC for setting the Existing Capacity Price Cap.

6.3.28 Some respondents pointed to a number of specific differences between Non-Fuel Operating Costs and Fixed Operating Costs:

- A number of respondents raised the issue of how to apportion NFOCs that are held centrally, which are not allocated to specific stations or units. A key issue is how in the context of a multi-unit station the fixed costs for the whole station should be allocated against the units being offered. It was argued there is a risk that not all of these units will be cleared in the auction resulting in a risk of under recovery of costs;

- One respondent stated that they do not consider that NFOCs are suitable to use in the Net Going Forward Cost formula without making adjustments. This respondent stated that NFOCs contain a portion of variable operating costs. The respondent stated that a station's operating expenditure overhaul costs are included in NFOCs and major overhauls are capitalised. The respondent concluded therefore, NFOCs will include an element of variable operating costs;
- One respondent argued that NFOCs do not include annual fixed costs, and as such are likely to considerably underestimate the fixed cost of running a plant in Ireland.

6.3.29 Some respondents requested that the SEM Committee provide more specific guidance on what costs will be allowed in USPCs, and argued that other markets provide more guidance than was included in the NGFC formula set out in the consultation paper (SEM-16-073). One respondent stated that they support a position which better defines fixed operating and maintenance costs similar to that defined in the PJM market.

6.3.30 A number of respondents that did not agree that NFOCs are suitable to use in the NGFC calculation raised general points about the consistency of these reports. Key points made in this regard included:

- One respondent stated that whilst Generator Financial Reports represent a true and fair view of the business, as required by any accounts, they do not provide any basis for regulatory interventions in competitive markets.
- One respondent described how there are likely to be substantial differences amongst submissions, which would require substantial effort to make sure all are on the same basis. This respondent also described how they are a report on history and do not provide reliable information on future costs, and how costs will change over time in the case of T-4 auctions. This respondent highlighted forecast error and uncertainty, and as a result suggested that a large margin for uncertainty should be built into bid limits.
- One respondent stated using NFOCs as a proxy for Fixed Operating Costs is likely to be flawed, data will be inconsistent, and argued that using historical cost is not appropriate for bid controls in a T-4 auction since costs will change over time.

6.3.31 One respondent described how the SEM Committee indicated that it may choose to make adjustments to the historical data, and stated it strongly opposed this if it were done without further engagement with the industry.

Treatment of unavoidable future investment costs

6.3.32 Some respondents expressed concerns that the overall design of the CRM discriminates against investment in refurbishments / upgrades, and resulted in a distortion in favour of new build capacity and against refurbished capacity. They pointed out that, unlike in GB and some US markets, the I-SEM CRM does not provide for multi-year guaranteed prices for refurbished capacity which does not meet the NCIRT threshold, which is set at quite a high level- high enough to preclude much refurbishment investment. Some respondents wanted the SEM Committee to revisit its decision, made in CRM Decision 2 (SEM-16-022) not to introduce a specific category of multi-year Reliability Options for refurbishment / upgrade investment, and to have low investment thresholds for these categories.

6.3.33 It was further pointed out that not only does the CRM design not have a multi-year Reliability Option for refurbishing capacity, the NGFC formula does not allow any existing capacity which is investing in refurbishment / upgrades, to include any proportion of that investment cost in its USPC, and that this further distorts competition in favour of new build, and discourages efficient investment in refurbishment / upgrades. It could also mitigate against upgrades required for environmental reasons.

Other issues related to NGFC / USPC methodology, process and data

6.3.34 Other key issues raised by respondents included:

- **Modelling the I-SEM versus modelling the SEM**. Some respondents questioned the appropriateness of the RAs using PLEXOS models based on the SEM to model unit specific infra-marginal rent in the I-SEM. One respondent stated that under auction format B buying additional capacity to address locational issues will erode the infra-marginal rent. There were also questions on modelling raised verbally at the emerging thinking workshop in Dundalk. One respondent stated that the proposed formula to define Net Going Forward Costs includes assumptions about the Administered Scarcity Price (ASP) and projected difference payments and this is subjective.
- **Concerns about the potential for uncertainty in key input assumptions and modelling**. The majority of respondents did not agree with the proposed process and data inputs. One respondent stated that there is no acknowledgment of the difficulties of determining accurate assumptions or carrying out accurate modelling, or recognition of the limited information that will be available to regulatory staff when carrying out these tasks. Another respondent highlighted forecast error and uncertainty, and as a result suggested that a large margin is required. One respondent stated that while it seems reasonable at this time, the RAs should share the dissemination of data with parties on a bi-lateral basis to ensure accuracy in their interpretation and analysis.
- **Objections to the ex-ante nature of cost reviews, level of regulatory scrutiny and consistency with international best practice**. One respondent argued that international precedents offer no support for the specific form of capacity market price controls currently proposed for the I-SEM, because controls in other markets offer greater flexibility, and rely on ex post scrutiny rather than ex ante as proposed for the I-SEM CRM. One respondent described how the proposal would require the RAs to determine and / or approve the Bid Limits which would make the market more regulated than market-based.

6.3.35 There are also some legacy comments from previous consultations about how eligibility will be determined for auto-producers, and how we will determine what proportion of an auto-producer’s maximum capacity will be subject to ECPC/USPC bid limits where some of that capacity is provided by generation, and some can only be provided by demand reduction. These issues could only be properly determined once the de-rating approach for auto-producers had been defined, which it was in SEM-16-082 (De-rating and Capacity Requirement

Methodology, published 8 December 2017). Auto-producers continued to seek clarification on how bid limits will be applied to them.

6.3.36 One respondent sought clarification with respect to the USPC setting process. They requested confirmation that the existing unit will apply to the CRM Delivery Body for a USPC, but that it will be the role of the Regulatory Authorities to review this application and make a recommendation to the SEM Committee.

Level of the ECPC

6.3.37 There were a range of views on the approach to setting the ECPC at 0.5 x Net CONE. The majority of respondents did not agree with the proposal to set ECPC at 0.5 x Net CONE, although we note that the majority of these responses were from owners of existing capacity, who would be the primary beneficiaries of a higher ECPC. However, there were some respondents who agreed with the proposed approach.

6.3.38 Common arguments advanced by those who favoured a higher ECPC were that an ECPC at the proposed level would prevent total cost recovery, undermine efficient investment incentives (discriminating against existing plant), threaten security of supply and create regulatory risk. Other respondents noted that a low ECPC would result in more USPC applications, which would create a burden on both regulators and the industry.

6.3.39 Some respondents felt the proposal to set the ECPC at 0.5 x Net CONE was inadequately justified.

6.3.40 Two other respondents suggested a figure of 0.75 x net CONE would be more appropriate. One of these respondents argued that existing generators will be reliant on new entrants to raise the price above the offer cap (ECPC), and suggested that the Existing Capacity Price Cap should be set at 75% x Net CONE until all the aforementioned interactions are fully understood. Another respondent also suggested setting the Existing Capacity Price Cap at a minimum of 0.75 x Net CONE, a level that they felt allows controlled exit in the Irish market.

6.3.41 Points made by those respondents who argued that the proposed ECPC was too low included:

- One respondent estimated that the proposed level results in a reduction of approximately 44% of the capacity revenue from the existing CPM, with no foreseeable increase in System Services revenue to offset this reduction. This respondent argued an ECPC at this level represents a significant challenge for the large number of ageing units on the Northern Ireland and Ireland system.
- One respondent stated that the most fundamental issue of ‘missing money’ would be inadequately addressed, which will likely be particularly acute in the case of peaking plant as well as ‘constrained on’ plant in the BM in respect of payments for non-energy actions under current proposals within SEM-16-059 (Offers in the I-SEM Balancing Market consultation paper).
- One respondent argued that the ECPC should be higher to allow for cost recovery, and reflect the risks associated with the Reliability Option.

- Another respondent described the proposal as discriminatory against existing capacity, suggesting that if the SEM Committee proceeds with an Existing Capacity Price Cap then it was recommended it is set at a much higher level than 0.5 x Net CONE to avoid the under recovery of costs, recognising the risks when setting the cap are asymmetrical, with significantly more downside (including administrative burden) resulting from underestimating it than over-estimating.
- One respondent described how the choice of 50% of the Net CONE as the Existing Capacity Price Cap is somewhat arbitrary, and argued that the indicative value of €38.90 kW / year lower than the average Non Fuel Operating Costs for all but one of the proposed technology categories. This respondent considered there to be a number of material issues to be re-examined relating to costs before any decision on the portion of Net CONE to select as the Existing Capacity Price Cap can be taken.
- One respondent stated that it is important that Net CONE is appropriately determined, and the determination of the ECPC must be set less in the manner of a price control.
- One respondent described how there is a risk that competitively determined prices will not be obtained if bid limits restrict participation, and introducing a bid limit could potentially promote tacit collusion since the bid limit would become a target price rather than letting competition define the value. The respondent described how the proposal would require the RAs to determine and / or approve the Bid Limits which would make the market more regulated than market-based.
- One respondent argue that there should not be different price caps for new build and existing capacity providers, and the uniform cap should continue to be set at 1 x Net CONE with no right to apply for a higher bid limit except for Local Security of Supply reasons.
- One respondent stated that they do not agree with the proposed process that seeks to impose tight price regulation across the market, and consider this a disproportionate approach that will distort competition and is not targeted at specific market power in the market.
- One respondent stated that there is no correlation between the Net CONE and the NGFC of units and so if one value changes, the other will not necessarily respond in the same way, and suggested that the Existing Capacity Price Cap should be determined solely off the NGFCs of generators.

6.3.42 By contrast, a number of respondents agreed with the proposed approach to set ECPC at 0.5 x Net CONE. One respondent commented that while the value seems appropriate in today's market, requested further clarity on the principles used to set the multiple and therefore how it will be set/ changed in the future.

SEM Committee Responses

6.3.43 The SEM Committee considers that the approach it set out to setting ECPC, USPCs and NGFCs within the CRM Parameters consultation is generally sound. In particular, the approach of not including sunk costs in NGFCs and hence USPCs is central to controlling market power in the first transitional auction. The approach of setting ECPC at 0.5 x Net CONE, and not including sunk costs in ECPC will result in outcomes that might be expected, absent market power, in a market where supply is significantly in excess of demand. We set out our position in detail below.

6.3.44 The SEM Committee has decided to use generator's reporting of Non-Fuel Operating Costs from historical generator financial reporting as a proxy for Fixed Operating Costs, but will review any evidence of the need for adjustments on a case-by-case basis, as part of the USPC application process. The SEM Committee is not convinced by the justifications provided by generators to explain why fixed costs are higher in the SEM than in other markets, but prefers to allow competition rather than regulation to drive out efficiency gains for the time being. Therefore the SEM committee does not plan to incorporating scope for efficiency gains in bid controls

6.3.45 However, following receipt of consultation feedback, it is appropriate to make two key changes to the approach to setting NGFCs (and hence USPCs):

- Unavoidable future investment: It is appropriate to allow a proportion of unavoidable future investment in NGFCs and USPCs; and
- The SEM Committee has decided to allow a 10% tolerance for estimation uncertainty in setting USPCs.

6.3.46 The SEM Committee has summarised its response to the points made above in relation to setting ECPC and USPCs under the same headings.

Excluding sunk costs from NGFCs, the ECPC and USPCs

6.3.47 The SEM Committee does not agree with the contention that our approach to setting ECPC and USPCs based on NGFCs is flawed or that it will harm competition. Furthermore, we reject the notion that our model is based upon "a flawed interpretation of the theoretical ideal of perfect competition, which is not even applicable to sectors with long run, irreversible investments", and this leads us to believe that "prices that deviate from strict definitions of short run marginal costs can be consistent with competitive behaviour".

6.3.48 On the contrary, the proposed controls are designed to simulate the effect of competition in a situation in which we have the real-world problem of market power. The proposals are a pragmatic solution to addressing market power. They will ensure that the market delivers prices which, in the short term, reflect the current excess of capacity over the Capacity

Requirement, whilst allowing them to rise in the longer term to the net cost of new entry or higher, when new investment is required.

6.3.49 In a fully competitive market, with an excess supply, absent the exercise of market power (both unilateral and co-ordinated), we would expect a bidder to include only its forward-looking costs in its capacity market offer. If it tried to include its sunk costs, it would substantially reduce its chances of winning in the auction, so we would expect it to include only those costs which are strictly necessary for its continuing operation in its bid.

6.3.50 However, market power may prevent the emergence of such a competitive outcome. Our bid caps are designed to mitigate the effects of market power in the CRM.

6.3.51 Once the current excess supply of old inefficient capacity has exited, we are expecting new entry to set the capacity price more frequently - see paragraph A.2.22 in Appendix D. In those years, prices will definitely diverge from the SRMC of supplying capacity, since new capacity will be allowed to bid up to 1.5 x Long Run Marginal Cost of Capacity (LRMC) and can be expected to bid at least its own LRMC.

6.3.52 Some generators may argue that it is only appropriate to constrain existing generators to bid at Net CONE, whilst there is a surplus of capacity (and market power persists), and that in the longer run, it is appropriate to allow existing generators to include sunk costs in their bids. However, it is likely that in years where no new capacity is required, existing capacity (which has the advantage of barriers to entry) will have a degree of market power. Without bid controls, existing capacity could bid up to Net CONE with little fear of losing in the auction, so that the auction would clear at or just below the total Net CONE even when no new capacity is required.

6.3.53 Now in years in which new entry is required, it may be that barriers to entry, such as the lack of available sites with planning permission and connection agreements, means that new build can win an auction by pricing significantly above Net CONE. This means that unless the SEM Committee continues to regulate bids of existing capacity to cover only NGFCs, on average the capacity market will clear significantly above Net CONE, i.e. in excess of a level which will allow efficient capacity to recover its total costs due to persistent market power. By this argument, regulation of existing bids is necessary to restrain market power in the longer run too.

6.3.54 It is not correct that the SEM Committee is denying generators the opportunity to recover their total costs. Firstly, a new build generator can bid up to 1.5 its (total) Net Cost of New Entry, and can receive a contract which guarantees it that level of cost recovery for 10 years-which incidentally is much greater certainty than under the current SEM. Therefore, when new entry is required, the clearing price (and all generators who are successful in the auction will receive at least the clearing price) may rise to 1.5 x Net CONE in years in which new entry is required. Some existing generators may not be able to bid at a level that covers their total costs, including sunk costs. However, that does not mean that the SEM Committee is denying them the opportunity to earn their total costs back, since their bids will not necessarily set the clearing price, and in-merit bids are paid-as-clear.

6.3.55 New entry is unlikely to be required in the next few years (except possibly to address locational constraints) since the market as whole is over-supplied. However, we anticipate that in the medium to longer term, once the existing old inefficient plant has responded to the new exit signals contained within the I-SEM, there will be new entry setting the clearing price frequently, possibly in most years.

6.3.56 The SEM Committee recognises that the proposals to require constrained-on generators to bid at short run marginal cost in the balancing market (for complex bid offer data that cover non-energy actions and a small subset of energy actions) may limit their ability to earn infra-marginal rent. However, we note that in a hypothetical situation in which there are no significant constraints, the generators which are constrained-on would not be running anyway, and would not be able to earn any infra-marginal rent either. Therefore, the regulation of the energy (balancing) market serves to take away the local market power conferred on constrained-on generators in the energy market by virtue of the transmission constraint.

6.3.57 Similarly, the regulation of out-of-merit bids in the capacity market serves to remove the local market power which may be conferred on a generator in the capacity market resulting from transmission constraints.

6.3.58 The SEM Committee does not have a statutory obligation to ensure that a market participant is able to recover all its costs, regardless of how over-supplied the market is. As we stated above, in a fully competitive market, with excess supply, absent the exercise of market power (both unilateral and co-ordinated) we would expect a bidder to include only its forward-looking costs in its bid. If it tried to include its sunk costs, it would substantially reduce its chances of winning in the auction, so we would expect it to include only those costs which are strictly necessary for its continuing operation in its bid. In such circumstances, we would not expect all generators to be able to finance their activities, and we would expect some to exit. There is no obligation on the SEM Committee to ensure that all the excess generation can recover its total operating costs.

6.3.59 The SEM Committee notes that some market participants have argued that there may be a specific issue with regard to plant which selected in the capacity market to meet a local capacity constraint and is dispatched to meet system constraints in the Balancing Market to a very material degree, or only operates to meet system constraints.

6.3.60 The SEM Committee also note that we have consistently stated during I-SEM High Level Design process and the I-SEM CRM Detailed Design process that the RAs do not preclude the need for other targeted mechanisms designed to ensure security of supply. For example, this may include mechanisms to address local system service requirements and income from such a mechanism may also help a generator recover additional efficiently incurred costs.

6.3.61 The SEM Committee recognises that there is a possibility that a generator which is critical to meet local system service requirements but not local capacity requirements, does not get awarded a Reliability Option. This could happen if it has high net going forward costs, and reflects those costs in its CRM auction offer. The CRM auction constraints do not reflect local system service requirements, and if the bidder is out-of-merit in the unconstrained CRM merit order, and not required for local capacity reasons, it will not receive a Reliability Option. After the auction, the TSOs will need to identify whether there are any local system service requirements that are not met by generation plants that are expected to remain available for the following capacity year, and identify economic and efficient solution to those issues.

6.3.62 Additionally, consistent with the SEM Committee decision set out in the Locational Issues decision (SEM-16-081), a locational capacity requirement would only be included in the CRM mechanism where the need is “clear and significant”. There remains the possibility that following the auction, the TSOs identify an unexpected localised security of supply issue - one that did not meet the definition of “clear and significant” before the CRM auction, but which the TSOs judge, following the results of the auction, may be a material risk to local security of supply. Whilst this is not expected, there remains the possibility that a targeted contracting mechanism may need to be put in place by the TSOs to address such an eventuality.

6.3.63 Constrained on plant will only be scheduled in the Balancing Market, and when constrained-on will be paid on the basis of its complex bid offer data, that are subject to regulatory limitations. Some market participants have argued that because they will be selling predominantly or exclusively at the level of their complex offers, rather than at the Balancing Market price, they may not be able to recover their sunk efficient costs in either the energy market or the capacity market, or from revenue from system services tariffs despite being critical to security of supply.

6.3.64 The SEM Committee is clear that any such generators will not be allowed to include their sunk costs in any net going forward cost calculation for a USPC. The decision to regulate complex bid offer data in the Balancing Market, is set out in the SEM Decision Paper on Complex Bid Offer Controls in the I-SEM Balancing Market (SEM-17-020).

6.3.65 However, in considering such concerns the SEM Committee, along with the TSOs, will continue to consider the need for and an appropriate framework for any additional mechanism to address particular local security of supply concerns. These considerations will take account of the overall energy, capacity and system services market framework and relevant Grid Code requirements. Further information will be provided on this over the coming months.

6.3.66 The SEM Committee does not agree that the proposals will discourage future investment. New investment will be guaranteed a fixed capacity price for 10 years, and they are allowed to include their total costs in their bid. The length of the price fix is more than in any other capacity market around the world, other than GB, which is an outlier. It is more than the fixed price term of any US capacity market. After the first ten years, they are subject to capacity variation, but the presence of a capacity market will give them greater revenue certainty than in an energy only market, which many European markets are. As discussed above, once the current surplus of old inefficient capacity has exited, we expect new capacity to be setting the clearing price in most years, and this will dampen the volatility of the capacity price.

6.3.67 We recognise that the proposals set out in the CRM Parameters consultation did not explicitly provide for existing capacity to include recovery of an appropriate portion of unavoidable investment required to keep existing capacity operational, and we address that issue below.

6.3.68 The SEM Committee believes that the proposed CRM is consistent with the State aid guidelines, although it recognises that the ongoing State aid notification process will ultimately determine consistency in this regard.

6.3.69 We also do not agree that our proposals discriminate between new and existing generation in a way which is unjustified, and inconsistent with the State aid guidelines. We note that the GB capacity market, which received State aid approval, has a different treatment of bid controls for existing and new generation in the same way as proposed for the I-SEM CRM, in that existing generators will be limited to bidding at 0.5 x Net CONE whereas new generators will be able to bid at 1.5 x Net CONE. The GB mechanism also has a different treatment of new and existing generation in terms of contract length, with the difference in contract length being more pronounced in GB (1-year vs 15 years) than the I-SEM (1-year vs 10 years).

6.3.70 We expand upon some of these points in more detail in 0.

Incorporating scope for efficiency gains in bid control

6.3.71 Overall, the SEM Committee does not accept all the explanations provided by generators for why SEM generators' costs are generally higher than international benchmarks, and thinks that there may be potential for generators to reduce their fixed costs. However, there are a number of practical difficulties in building in specific efficiency gain targets into bid controls for the first transitional auction. The available data on generator fixed costs from historical Generator Financial Reporting templates is quite high level, which makes it difficult to know to what extent different generators have employed different reporting approaches, for instance with respect to the treatment of overheads.

6.3.72 The SEM Committee is persuaded that in the current circumstances, where installed capacity significantly exceeds the Capacity Requirement, the move to a competitive CRM is likely to drive a large proportion of the potential efficiency savings from generators. The SEM Committee recognises that those generators which are in constrained zones may not face such strong competitive pressure, but where these individual unit submit applications for a USPC, its cost submission will be scrutinised on a case-by-case basis. Whilst the SEM Committee will not seek to reflect the potential for efficiency gains on USPC bids on a systematic basis, each USPC bid will be subject to ex ante scrutiny. The SEM Committee will review each bid on a case by case basis, and may disallow or adjust certain cost bids.

6.3.73 The SEM Committee does not accept that the higher fixed costs of generators on the island are predominantly due to the higher penetration of renewables and the resulting running regime. In this regard, the SEM Committee notes that the unit fixed costs were, on average higher in the earlier years of regulatory reporting, when the penetration of renewables was lower, and before DS3 requirements began to impact. If anything, reported fixed cost have been decreasing as the renewables penetration has increased.

6.3.74 The SEM Committee accepts that some costs, such as gas transportation cost are higher in Ireland / Northern Ireland than in GB, and that economies of scale may have some impact.

6.3.75 Historical Generator Financial Reporting does not contain strong evidence for inflation driven increases in fixed operating costs. The SEM Committee does not intend to build in any automatic indexation process into setting USPCs (the ECPC will be indexed automatically, since it is a function of Net CONE, which is inflation indexed). It will be for the applicants to make the case that their costs have increased (whether in line with inflation or otherwise) in USPC applications.

Using NFOCs as proxy for Fixed operating costs in NGFC estimates

6.3.76 The SEM Committee notes the points made by the respondents about the accuracy of using NFOCs as a proxy for fixed operating costs in NGFC estimates. The SEM committee notes that Generator Financial Reports have not been used in this way before, and that there may be discrepancies in the way in which generators have treated certain costs, such as in allocating overheads to specific units. In this regard, the SEM Committee notes that any existing generator will have an opportunity to submit a USPC application on a unit by unit basis, and explain why it consider it appropriate to make adjustments to the way in which it has historically submitted its Generator Financial Reports for the purposes of setting a USPC. Additionally, as discussed below, the SEM Committee notes that there are other uncertainties in estimating NGFCs, such as modelling assumptions and as a result, the SEM Committee intends to introduce a 10% tolerance around NGFC estimates in order to cover the aggregate estimation uncertainty.

Treatment of unavoidable future investment costs

6.3.77 The SEM Committee notes the comments made by respondents in relation to the lack of incentives contained in the proposals set out SEM-16-073 to invest appropriately to refurbish / upgrade capacity. The SEM Committee notes that in some other jurisdictions, such as in the US PJM capacity market, bid controls explicitly allow existing generators to include a proportion of the (un)avoidable investment in their bids.

6.3.78 Before discussing this further it is worth clarifying potentially confusing terminology. In PJM they refer to avoidable investment costs, i.e. costs which are avoidable if the unit shuts down. However, we shall use the term “unavoidable investment costs” for the same concept, i.e. costs which must be incurred if the capacity is to be delivered.

6.3.79 PJM have an explicit element in their “avoidable cost formula” called the APIR (Avoidable Project Investment Recovery Rate) which is the product of the project investment (PI) and the levelised Capital Recovery Factor (CRF). The CRF is a published schedule, where the CRF is a function of the estimated remaining life of the plant, which in turn is assumed to be inversely related to the age of the existing plant. The formula contains some banding, and does not appear to be technology specific, or to take into account any plant specific circumstances. The assumptions built into the PJM levelised CRFs are not necessarily consistent with SEM assumptions. For instance:

- A plant which is more than 25 years old and is making an investment is assumed to have a minimum of 5 years of remaining life over which to recover the cost of new investment, whereas SEM BNE assumptions are for a 20 year economic life;
- Capital market conditions will reflect local PJM factors, and the cost of capital may be materially different in PJM from the I-SEM.

6.3.80 At this point in time, the SEM Committee does not propose to publish generic levelised CRFs (like PJM does) before the first transitional auction. It may be that for the first transitional auction, which is a T-1 auction, no existing plant is planning to make any investment. For the first transitional auction, the SEM Committee proposes to calculate Capital Recovery Factors on a case-by-case basis, based on the following approach / principles:

- Where a bidder wishes to include an element of unavoidable future investment in its USPC application it should provide the SEM Committee with details of the proposed investment in line with requirements set out in Appendix F. The applicant will be required to specify, *inter alia*: the quantum of investment required with supporting evidence, e.g. quotes from suppliers; the reason for the investment; the MW of capacity delivery to which it relates; and the economic life of the investment project.
- For each investment project, the SEM Committee will determine an appropriate period over which the investment can be recovered. The recovery period will be a number of years, n, up to maximum of 10 years- i.e. no longer than the maximum fixed price Reliability Option for new investment that exceeds the NCIRT. The recovery period will not exceed the remaining economic life of the capacity market unit, but may be less than the remaining life of the unit where the applicant can convince the SEM Committee that the economic life of the investment is less than the remaining economic life of the capacity unit.
- Where the project is deemed to have a recovery period of n years, the SEM Committee would propose to allow the investor the opportunity to recover its investment by including an element in its bid for each of the next n years, which reflects:
    - The net value of its investment (i.e. net of any residual value at the end of the deemed recovery period) based upon straight line depreciation. For instance, where a bidder proposed to invest in increased connection capacity, the connection capacity may have residual value beyond the economic life of the capacity market unit;
    - Any increment in annual fixed operating costs, to maintain the investment; and
    - A return on the investment consistent with the current SEM BNE WACC.
- The SEM Committee will only allow investment which is strictly necessary to deliver the uncommissioned capacity to be included in the calculation- this will prevent “gold-plating”, and is consistent with the principles for determining the quantum investment which can be used to determine whether the NCIRT has been exceeded. Where an investment is being made to enhance ancillary service provision, but not to enhance capacity, we would not expect these costs to be recovered from the capacity market via an enhanced USPC.

6.3.81 The SEM Committee recognises that a proportion of the “future” investment may have been spent before the auction, as will be the case with new build, where an investor will be required to spend money upfront to meet the Qualification criteria. However, allowable “future” investment for USPC applications should not relate to capacity that has already been commissioned, or otherwise already committed to before the auction. It is conceivable that a USPC applicant may need to make an investment that does not increase capacity (e.g. required for compliance reasons) and does not result in a commissioning event. The SEM Committee does not preclude allowing such investment to be considered unavoidable, but the burden of proof will be on the USPC applicant to demonstrate the necessity of the investment.

6.3.82 These proposals are in no way intended to ensure that a bidder is guaranteed to recoup its investment or to earn its WACC. The bidder may choose to bid up to its resulting higher USPC in each auction for the next n years, but shall be exposed each year to the normal commercial risk that it loses in the auction.

6.3.83 The SEM Committee notes that the inclusion of an allowance for unavoidable future investment may create some gaming opportunities, particularly for those bidders in constrained zones who face limited competition. Therefore:

- Ex ante, whilst it wishes to incentivise genuine investment, it notes that the burden of proof of necessity will lie clearly with the applicant.
- The SEM Committee notes that appropriate ex-post monitoring should be put in place to ensure these provisions are not abused (i.e. generators claiming that they intend to make an investment in order to obtain a higher USPC, when they have no intention of making an investment). Unlike with new build, which requires the investor to have invested in connection agreements and to have met various other pre-conditions to prior to Qualifying, some qualifying refurbishment / upgrade investment may not require pre-commitment, and hence make it easier for a generator to “change its mind”. The generator will be required to send a report outline the progress of the investment. If the amount invested is material different from the ex-ante claim, the SEM Committee may pursue remedial action, making an adjustment to USPC for subsequent auctions, adjusting the price of pay-as-bid Reliability Options, or pursuing the bidder under market manipulation rules.

6.3.84 In summary, the resulting position for an existing generator looking to invest is as follows. Where it:

- Invests in incremental capacity which meets the NCIRT threshold, and other criteria to obtain a multi-year Reliability Option, it will be able to bid this incremental capacity into the CRM auctions at up to 1.5 x Net CONE;
- Makes an investment which does not meet the criteria to be able to get a multi-year Reliability Option it will be allowed to include a proportion of that investment in its estimate of Net Going Forward Costs, and hence in its USPC application. The proportion that will be allowed will be determined by the SEM Committee in discussion with the bidder on a case by case basis, in accordance with the principles set out above.

Other issues – assumptions, uncertainty and modelling

6.3.85 The SEM Committee accepts that there is a significant degree of uncertainty around estimating the NGFCs for individual units, including uncertainties over the estimates of future Fixed Operating Costs (where historical costs may not be a fully accurate guide to future costs), Infra-Marginal Rent and ancillary service income for individual units.

6.3.86 The SEM Committee notes the points made about the difference between the SEM and the I-SEM, and questions raised about whether models which have been built for the SEM are appropriate to model infra-marginal rent in the I-SEM. Key differences between the SEM and the I-SEM which may impact on price are:

- The I-SEM orders types for DAM, IDM and BM will be based on a “Simple” bid concept as they will include all components required to form a price. Generators will therefore internalise risks associated with start-up and no-load costs. Whereas in the SEM, generators bid complex bids made up of a start-up, no-load and incremental price bids, the pricing algorithm takes in consideration the different components in order to determine if the bid is in merit or not. We would not expect this to make a systematic difference to energy prices since we would expect generators to factor an expectation of start-up costs and run times into the single price. Generators may incorrectly predict run times and the MWhs over which start-up and no-load can be recovered, a risk that they do not face in the SEM. Prices will outturn differently from SEM prices as a result, but arguably if there is a systematic rather than random difference in prices, we would expect prices to be higher if generators factor any premium into their single-price offers as a result.
- In the SEM, the Bidding Code of Practice requires generators to bid at cost. In practice, in the I-SEM energy market, all generators will be allowed to bid above cost in the DAM and the IDM and reflect scarcity in their pricing. Only those generators who have their complex bids and offers accepted in the BM, will be subject to cost based regulation, and then only if the Complex Offer is higher than the Balancing Market Price. Complex offers will predominantly only be accepted for non-energy reasons[25]. The PLEXOS modelling of energy revenues assumes that all generators will bid at cost, again this may result in the current PLEXOS modelling under-estimating revenues, and hence under-estimate Infra-Marginal Rent.

[25] Complex bid offer data will be used by the TSOs as part of their scheduling and dispatch process. This will result in Bid Offer Acceptance (BOA) quantities for generator units that will mainly be used for non-energy actions. However, the TSOs’ scheduling and dispatch process may also include early energy actions. However, the TSOs are discouraged from taking early energy actions by the Long-Notice Adjustment Factor (LNAF) and will deviate from Physical Notifications (PNs) only where necessary, we anticipate that use of complex bid offer data for early energy actions will be limited

6.3.87 There is a third reason why our approach is more likely to over-estimate NGFCs rather than under-estimate them. The current modelling does not assume any plant exits as a result of losing the first transitional auction. This means that we take a conservative approach to modelling energy prices, since plant closure can be expected to lead to higher energy prices, higher Infra-Marginal Rent and hence lower NGFC estimates.

6.3.88 Notwithstanding the view that our estimates will generally take a conservative view of NGFCs, we plan to explicitly introduce a 10% margin for estimation uncertainty in modelling NGFCs. This approach is similar to the approach employed in PJM, which also includes a 10% margin in their "avoidable cost formula".

6.3.89 As the I-SEM and CRM develop the SEM Committee will continually develop its modelling capability and make use of the most accurate estimates available at a point in time.

USPC process

6.3.90 The SEM Committee will adopt the following approach to setting USPCs:

- The RAs have modelled the NGFCs for each significant capacity market unit, and may continue to update their estimates in responses to material changes in fuel and carbon prices and exchange rates, and for revised demand forecasts resulting from the publication of the 2017 GCS;
- Any bidder wishing to submit a USPC application will be required to fill out the template in Appendix F, justifying their proposed USPC;
- The Capacity Provider submits it's USPC application directly to the RAs;
- The RAs may request further information / clarification of the application from the bidder as part of the USPC application review;
- The RAs may adjust their estimate of the NGFC for the capacity market unit in question, based on new evidence submitted in the USPC application;
- The RAs will make a recommendation on the USPC for the unit in question to the SEM Committee. That recommendation will be the lower of the RAs' revised estimate of the unit's NGFC plus 10%, or the USPC application submitted by the bidder.

6.3.91 The SEM Committee wish to clarify that USPC submissions should be made directly to the RAs and not to the CRM Delivery Body. Within CRM Decision 3 (SEM-16-039) section 3.4 refers to applications for a higher bid limit being submitted to and reviewed by the CRM Delivery Body, however since then we consider an approach where USPC applications and subsequent review is directly carried out by the RAs as being pragmatic given the timetable for the first Transitional Auction.

Other issues - ex ante regulation and consistency with international best practice

6.3.92 The SEM Committee does not agree that the proposed regulation is materially different from international best practice, and that the combination of I-SEM energy and capacity market regulation will prevent generators from recovering revenue in ways that other regimes do not.

6.3.93 It is correct that the GB electricity market, which also caps the bids of existing generators at 0.5 x Net CONE[26], does not impose SRMC based pricing on offers. However, the I-SEM will not impose SRMC based regulation on generator activity in the Day-Ahead Market and Intra-Day Market. Only complex bid offer data accepted in the BM, predominantly those accepted for non-energy reasons, will be subject to the ex-ante bid controls. In the SEM, the equivalent of non-energy actions in SEM is the dispatch balancing costs, which represented approximately 10% of total revenues in SEM.

6.3.94 The SEM Committee notes that the proposed energy market/capacity market regulatory treatment of generators behind a constraint is similar (and arguably lighter) than for analogous generators in some US markets such as PJM. In PJM, any generator which fails the Three Pivotal Supplier test in an energy market zone (i.e. behind a constraint), and is deemed to have market power is subject to cost based regulation of its energy market offers. Note that in PJM, cost based regulation applies to all energy bids where the generator fails the Three Pivotal Supplier test- a test all generators would be likely to fail, if it was applied to the I-SEM (see SEM-16-010 and SEM-16-039). In the I-SEM, only complex bid offer data (predominantly those accepted for non-energy reasons) in the balancing markets are subject to ex ante bid controls. Regulation of the capacity market (with the additional changes to reflect unavoidable investment) will be similar in the I-SEM to that in US capacity markets such as PJM, given that most if not all generators would fail the Three Pivotal Supplier test in the capacity market. This is true both if the Three Pivotal Supplier test was applied to the all-island capacity market as a whole, and also if applied to a constrained zone with the all-island market. Hence the contention that analogous regulation is lighter in the I-SEM than in PJM.

6.3.95 It has been argued that one way in which our proposal differs from best practice is that we plan to impose ex ante scrutiny of unit specific bids, rather than ex post. If bidders comply with the rules and/or ex post scrutiny is applied with appropriate diligence, it should result in exactly the same auction results and incentives as ex ante controls. The only relevant difference is administrative burden, ex ante scrutiny may result in scrutiny of bids that do not turn out to be relevant. The SEM Committee believes that the extra administrative overhead of ex ante scrutiny is appropriate and proportionate given the level of market power in the I-SEM, and the overriding consumer interest. There are some key difference between the GB auction and the I-SEM auction which lead the SEM Committee to conclude that ex ante scrutiny is proportionate in the I-SEM:

- The level of market power is high in the CRM and the SEM Committee is concerned about unilateral and co-ordinated market power (see discussion in SEM-16-039), particularly in the first transitional auction, where there is little scope for new entry; and

[26] With a similar provision for unit specific bid limits

- Constraint issues are more material than in GB, which has lead the SEM Committee to conclude that it may be necessary to award pay-as-bid Reliability Options to some Capacity Providers.

Other issues- treatment of auto-producers

6.3.96 The SEM Committee also considers that it is appropriate to clarify the application of bid limits to auto-producers in response to comments from auto-producers. Consider the case of an auto-producer with nameplate capacity N MW, and a connection which permits a Maximum Export Capacity of M MW. Let us assume that its own consumption on site is C MW, such that N-C<M, i.e. whilst it may be able to physically export M MW, it can only do so by demand reduction. In SEM-16-082a we decided that the de-rating factor for an auto-producer would apply to the Maximum Export Capacity M. Thus if the relevant de-rating factor is d%, if the auto-producer were treated as a normal generator, it would be required to bid d% of M at no more than its bid limit (ECPC or USPC if it obtains one). However, if M > N-C, this would effectively make it mandatory for an auto-producer to offer in demand reduction and be subject to a bid limit, whereas other demand reduction does not face mandatory CRM bidding and is not subject to a bid limit other than the Auction Price Cap, if it voluntarily participates. Therefore, we wish to clarify that for an auto-producer:

- Demand reduction offered will be placed on an equal footing with other DSUs in the I-SEM CRM, and will not be required to offer capacity into the auction, and will not be subject to the ECPC or a USPC. It will only be mandatory[27] for an auto-producer to offer up to d% of (N-C) into the CRM auction if N-C is less than M, and this d% of (N-C) volume will be subject to the same ECPC or USPC bid limits as other existing generation. Where d% of (N-C) is less than d% of M, the auto-producer may choose to offer this “demand reduction” into the CRM, and if it chooses to offer some of all the “demand reduction”, this component will not be subject to ECPC (or a USPC). This is illustrated in Figure 8;
- If N-C is greater than M, the auto-producer will be mandated to offer d% of M into the CRM auction[28], no more, no less[29]. This "generation component" volume (i.e. the volume of capacity delivered from generation) will be subject to the ECPC/ a USPC, the same as any other generator;
- For the purpose of calculating the USPC for an auto-producer, we will only apportion that proportion of its fixed costs which is consistent with the “generation component” to the NGFC calculation. Consider the example of an auto-producer which has 100MW of nameplate generation, 40MW of demand, an 80MW Maximum Export Capacity, a de-rating factor of 90% and total annual fixed costs of €5m for its generation. Its de-rated capacity is 72MW, but the “generation component” of its capacity is only 60MW, so it only has to bid 60MW and only 60MW is subject to ECPC (or a USPC). If the auto-producer decides to offer the full 72MW of possible capacity, the 12MW between 60MW and 72 MW can be offered at any price up to the Auction Price Cap. If the auto-producer wishes to apply for a USPC on its mandated 60MW of capacity it can, but only 60% of the €5m fixed cost will be taken into account.

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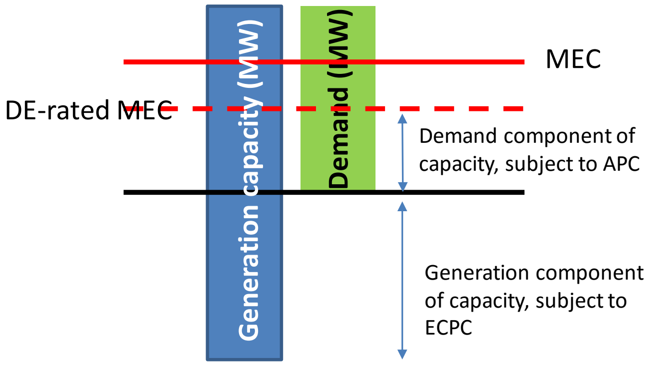
[27] Unless it notifies the CRM Delivery Body that it is going to close- i.e. subject to the same provisos that apply to mandatory bidding by existing non-intermittent generators (now called variable generators within the CMC draft issued as SEM-17-004a)

[28] Again subject to the same proviso as above

[29] given that DECTOL is set to zero for non-DSUs, and INCTOL is set to zero for all technology classes

- The auto-producer will need to submit evidence as part of the qualification process to justify any portion of its capacity which could only be provided by demand reduction.

Figure 8: Example where nameplate capacity less consumption less than Maximum Export Capacity



Other issues – treatment of supported generation

6.3.97 The SEM Committee is of the view that the approach to calculating NGFCs needs to be clarified with respect to supported Capacity Providers. As set out in CRM Decision 1, there are a range of Capacity Providers in Ireland and Northern Ireland that receives support outside the normal energy, capacity and ancillary service markets, and this generation is eligible to compete in the CRM auctions. For example:

- A range of renewables / low carbon support mechanisms which operate separately in both Ireland and Northern Ireland;
- The PSO backing for peat fired power stations in Ireland and legacy Generation Unit Agreements (GUAs) in Northern Ireland.

6.3.98 The SEM Committee wishes to clarify that if any generator supported by such a support scheme applies for a USPC, the calculation of NGFCs for supported generation will take into account any income that generation may receive via support schemes. The SEM Committee will only approve a USPC where a supported unit cannot otherwise cover its going forward costs, even with support payments.

6.3.99 The SEM Committee thinks that it is also worth clarifying the treatment of additional sources of income (e.g. heat sales in the case of CHP plant or gypsum sales in the case of plant retrofitted with FGD) will also be taken into account in the NGFC calculation used to set USPCs. Furthermore, if a CHP plant seeks to make a USPC application, the SEM Committee will apportion an appropriate proportion of the fixed costs to thermal capacity, and not allow an applicant to apportion all fixed costs to electrical capacity.

6.3.100 The SEM Committee notes that it has always been clear that there remains the possibility for other targeted interventions to support local security of supply, and if any contracts are put in place in future which overlap with an auction's capacity delivery period, income from such contracts will also be taken into account in calculating NGFCs.

Level of the ECPC

6.3.101 The SEM Committee has decided to set the ECPC at 0.5 x Net CONE. It is important to note that the ECPC performs two key functions, and the level of the ECPC needs to reflect these two key functions.

6.3.102 Firstly, it limits the ability of generators with market power, but with low NGFCs to exercise their market power through making high offers. Given the significant concerns about market power in the CRM (see SEM-16-010), it is important that the ECPC is not set at a level significantly above where we expect the market to clear in current market conditions. As we explained in the consultation document (SEM-16-073), and re-iterated in our response on sunk costs, we would anticipate that in the current market, with significant capacity in excess of the Capacity Requirement, in the absence of market power we would expect the auction to clear well below Net CONE, and not far from 0.5 x Net CONE.

6.3.103 Secondly it provides a filter to ensure that only those USPC applications which the RAs need to scrutinise (because they may have a material impact on the clearing price or pay-as-bid prices) are scrutinised. If the ECPC is set too low, then offer prices which are below the clearing price (and therefore will have no impact on the clearing price or pay-as-bid prices) will need to be reviewed, imposing an unnecessary administrative burden on both the RAs and bidders.

6.3.104 The SEM Committee considers that setting the ECPC at 0.5 x Net CONE strikes an appropriate balance between the objectives of protecting consumers from the potential for bidders to exercise market power, and not placing an excessive workload on the RAs and market participants.

SEM Committee Decision

6.3.105 The SEM Committee has decided that:

- **ECPC**: The Existing Capacity Price Cap (ECPC) will be set at 0.5 x Net CONE. Our current estimate of the ECPC for the first transitional auction is €38.77/de-rated kW. However, the SEM Committee may revise the estimate of Net CONE where there is a material change to the de-rating factor as a result of the application of the de-rating methodology by the TSOs to the BNE plant, in which case the updated Net CONE value will be calculated by the RAs, approved by the SEM Committee and published by the TSOs as part of the Initial Auction Information Pack to be published in early July;
- **NGFCs:** The RAs will calculate the NGFC for a generator based on the following formula:

  NGFC = Max [(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets + appropriate proportion of unavoidable future investment),0] + Expected Reliability Option difference payments

  Where the appropriate proportion of unavoidable future investment will be determined on a case-by-case basis

- **USPC**: Unit Specific Price Caps will be set based upon Net Going Forward Costs (NGFCs) according to the following formula:

  Max allowed USPC bid = 110% x RAs' NGFC estimate, updated following review of USPC application

- **Treatment of auto-producers**: The treatment of auto-producers is set out in paragraph 6.3.96.
- **Treatment of supported generation**: If any generator supported by a support scheme applies for a USPC, the calculation of NGFCs for supported generation will take into account any income that supported generation may receive via support schemes. The SEM Committee will only approve a USPC where a supported unit cannot otherwise cover its going forward costs, even with support payments.

6.3.106 The SEM Committee will continue to consider issues relating to plant which is both selected in the capacity mechanism to meet local capacity requirements and that are constrained-on in the Balancing Market to meet system constraints to a very material degree, or only runs when constrained-on.

6.3.107 The SEM Committee recognises that this issue needs to be considered further and there may be a need to put in place targeted contracting mechanisms to address local security of supply requirements which may emerge after the auction. This possible need for contracting flexibility was recognised in SEM-16-081 (CRM Locational Issues Decision paper) and SEM-14-108 (DS3 System Services Procurement Design and Emerging Thinking Decision paper). The SEM Committee, along with the TSOs, will continue to consider the need for an appropriate framework for any such mechanism. These considerations will take account of the overall energy, capacity and system services market framework and relevant Grid Code requirements. Further information will be provided on this over the coming months.

6.4 DEMAND CURVE PARAMETERS

Summary of consultation

6.4.1 The Capacity Requirement is a key input into the demand curve. In CRM Decision 1 (SEM-15-103) the SEM Committee decided to retain the existing 8-hour Loss of Load Expectation (LOLE) standard in defining the Capacity Requirement. However, the I-SEM Capacity Requirement is to be defined in de-rated MW terms[30], and to be based on the "least regret cost scenario"[31].

6.4.2 In CRM Decision 2 (SEM-16-022) the SEM Committee decided that the Capacity Requirement in each of the transitional years will be set based on the demand forecast for the last transitional year. At the time of the CRM Decision 2, it was envisaged that the last transitional year, would be CY2020/21. However, following the stock-take and the decision to delay the go-live of the I-SEM to May 2018, in Section 2, the SEM Committee decided that CY2021/22 would become a transitional year, so the Capacity Requirement for each of the transitional years will be based on the demand forecast for CY2021/22.

6.4.3 In CRM Decision 3 (SEM-16-039) the SEM Committee decided to use a sloping demand curve, rather than a vertical demand curve (set at the Capacity Requirement). Nevertheless the Capacity Requirement remains a key input to the demand curve. CRM Decision 3 stated that the slope and position of the demand curve would be defined during the CRM Parameters consultation but that the SEM Committee is minded to use the following principles:

- System security (Reliability) and economic efficiency:
  - Should be consistent with the security standard of maintaining the 8 hours per Capacity Year LOLE standard set out in CRM Decision 1;
  - Should, at a minimum, reflect an economically efficient trade-off between price of Reliability Option and value of extra reliability[32];
- Competition:
  - Should reduce susceptibility of the auction to market power (in conjunction with other market power controls);
- Stability (price volatility);
  - Should reduce price volatility impact from small variations in market conditions and administrative parameters, including lumpy investment decisions, and demand forecast changes; and
  - Should limit the frequency of outcomes at the Auction Price Cap.
- Practicality;
  - Should perform well under a range of market conditions, including changes in administrative parameters and administrative estimation errors.

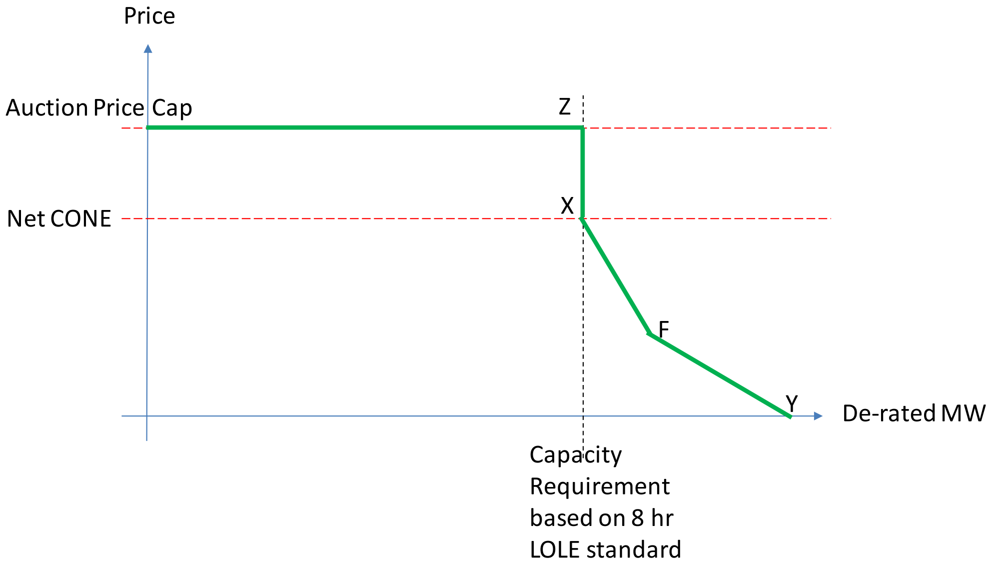
[30] as opposed to nameplate MW as under the SEM
[31] as opposed to the median scenario, as under the SEM
[32] Value of Lost Load x reduction in unserved energy

6.4.4 The CRM Parameters consultation (SEM-16-073) discussed the above principles in detail and how they should influence the setting of the slope and the position of the demand curve. It also presented international experience of both the shape and positioning of demand curves.

6.4.5 In SEM-16-073, consistent with the above principles and decisions, for the first transitional auction the SEM Committee proposed a curve shape as illustrated in Figure 8 below:

- Setting the demand curve for the first transitional auction horizontal at the Auction Price Cap between 0MW and the Capacity Requirement[33];
- Making the demand curve pass through point X where the price = Net CONE and quantity equals the Capacity Requirement, analogous to the price and volume[34] which determine the Annual Capacity Payment Sum in the SEM CPM; and
- Making the demand curve vertical between the Auction Price Cap and Net CONE, at a level of MW consistent with the Capacity Requirement. The curve is vertical at the Capacity Requirement based on the principle that the 8-hour standard is the minimum acceptable level of system security[35], and we are prepared to pay up to the Auction Price Cap to achieve that standard.

Figure 8: Proposed demand curve shape



[33] In SEM-16-073 the Capacity Requirement was envisaged to be based on the demand forecasts for 2020/21, but consistent with the decision to make 2021/22 a transitional year, this would now be based on the 2021/22 demand forecasts

[34] SEM volume is specified in nameplate MW (with an equivalent capacity credit for wind), not de-rated MW, and prices are per unit of nameplate capacity, not de-rated capacity

[35] If less than the Capacity Requirement is bid at the Auction Price Cap, in theory, the auction could end up with less than the "minimum" standard.

6.4.6 Point Z in Figure 8 represents 1.5 x Net CONE and would lead to payments to capacity providers which are 1.5 times higher than under the SEM CPM.

6.4.7 For the transitional auctions, were we know there is significant installed capacity in excess of the Capacity Requirement, greater focus should be on the slope and shape of the curve at volumes in excess of the Capacity Requirement. As illustrated in Figure 8, the key parameters which determine the shape and positioning of the curve to the left of the Capacity Requirement are:

- The **zero-crossing point**, that is the level of excess capacity at which the auction should be able to clear at a zero price (point Y);
- Whether there is another **inflection point** (drawn as point F) at which the curve changes slope.

6.4.8 The CRM Parameters consultation set out three options for the form of the demand curve, based upon the indicative Capacity Requirement at that time. The latest estimate of the Capacity Requirement is 7,380MW but the actual Capacity Requirement will be finalised in June and published in early July 2017.

6.4.9 All three options presented had a demand curve which is horizontal at the Auction Price Cap from 0MW up to the Capacity Requirement, and are vertical at the Capacity Requirement between the Auction Price Cap and Net CONE. The options differed below a price of Net CONE as follows:

- Option A: The curve has a flat slope, without inflection from Net CONE to a zero-crossing point at 20% in excess of the Capacity Requirement;
- Option B: The curve has a flat slope, without inflection from Net CONE to a zero-crossing point at 10% in excess of the Capacity Requirement;
- Option C: The curve has a point of inflection at a point on the EUE saving /kW curve from about 25% above the indicative Existing Capacity Price Cap (ECPC). After the point of inflection, the curve slopes more gently down to a zero-crossing point at 20% in excess of the Capacity Requirement.

6.4.10 These options are illustrated in Figure 9 below, which is a version of Figure 13 of SEM-16-073 expressed as a percentage of the Capacity Requirement.

Figure 9: Demand Curve Options

6.4.11 SEM-16-073 noted that we may choose to employ hybrid / intermediate options.

6.4.12 Respondents were asked which of Options A, B or C they thought was appropriate for the first transitional auction and whether they had any other comments on the shape and/or positioning of the demand curve for the first transitional auction.

Summary of consultation responses

6.4.13 There was a range of different opinions with support for all three options in varying degrees, with more respondents favouring Option A. Some respondents proposed their own variants, and others set out the principles that they believe should guide the setting of the demand curve.

6.4.14 A number of respondents favoured Option A, as the best compromise between procuring excess capacity and ensuring sufficient capacity for the first transitional auction (although other respondents advanced the same arguments for Option B), and is prudent for a smooth transition into I-SEM. Key arguments advanced in favour of Option A were:

- Some respondents described how a more gently sloped (shallower) demand curve will help to reduce price volatility in the capacity price, which may otherwise prevent the capacity market from providing a stable, credible investment signal;
- Some respondents described how Option A will increase the likelihood that additional capacity above the Capacity Requirement is procured, and it was argued that this will reduce the impact of the lumpiness issue and reduce locational concerns;
- One respondent in favour of Option A described how both Options B and C will result in a more radical level of plant exit creating a potentially unnecessary entry signal for plant in the T-4 auction;
- Another respondent in favour of Option A also agreed that a zero-crossing point of 15-20% in excess of the Capacity Requirement is more appropriate for a small system with limited interconnection.

6.4.15 A few respondents who favoured Option A for the first T-1 auction suggested adopting a curve closer to Option C for the following year and subsequent years, once market participants and the Capacity Market Operator have gained experience in the auction format:

- One of these respondents suggested that subsequently a consultation on the parameters of Option C should be performed.
- Another respondent stated that the zero-crossing point of 20% seems suitable for the transition, suggesting there would still be merit in procuring extra capacity if possible, at an economic price.

6.4.16 Some of other respondents favoured Option B for the first transitional auction:

- Some respondents described how it strikes a good balance between simplicity and not over procuring capacity, between a shallow demand curve and outturn capacity price.

- One respondent in favour of Option B stated that procuring 20% more capacity than needed seems overly generous with customers' money and beds in an existing suite of unreliable plant coasting on locational blessings.
- One respondent suggested that once the TSOs are able to resolve identified modelling issues they believe it would be appropriate to move to a steeper demand curve akin to Option B.

6.4.17 One or two respondents stated that they favour Option C for the first transitional auction, which more closely mirrors the shape of trade between incremental capacity and reduced cost of Expected Unserved Energy (EUE).

6.4.18 Other respondents suggested slightly different variants:

- One respondent stated that they did not believe that any of the three options proposed fully balance the risk of system security and costs of over-procuring capacity. The respondent suggested a solution that would strike such a balance is akin to Option B whereby instead of an inflection point, the curve would reflect the Reduced EUE as a way of providing value to the customer.
- One respondent stated that they believed that the shape of the demand curve for the first transitional auction should extend from Net CONE to a zero-crossing point at approximately 8,250MW. Describing how this is akin to Option B but would realise the costs to the consumer by reflecting the Reduced EUE curve whereby the value to the consumer is effectively zero at 8,250MW.

6.4.19 Other respondents had more general comments on the principles to be applied in determining the demand curve, both for the first transitional auction, and in subsequent years:

- One respondent urged the RAs to adopt a cautious approach in the initial years, suggesting that the interaction between the demand curve and the Local Capacity Constraints is important here.
- One respondent stated that market participants would also value greater clarity on the approach to set the demand curve for the subsequent T-1 and T-4 auctions.
- Another respondent described how they want to see a predictable capacity price, particularly during the transitional period, without volatile jumps or falls in revenue.
- Another respondent stated that it is not appropriate to position the demand curve to take account of the capacity contribution of de minimis generators when there is no mechanism in the market to direct any rewards to de minimis generators for this capacity contribution.
- Another respondent suggested that the demand curve for future years must be subjected to the rigour of detailed analysis and a full consultation with industry.
- Another respondent stated that they believe that more consultation is required on this as there are outstanding questions that need to be addressed.

SEM Committee Response

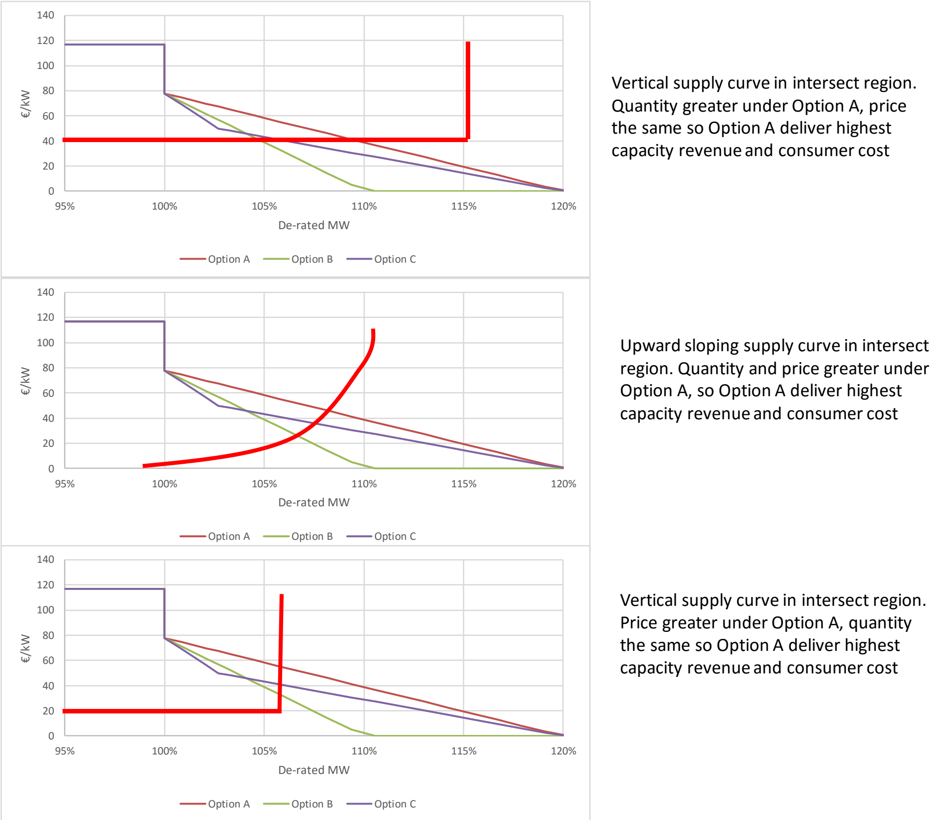
6.4.20 The SEM Committee set out its analysis of the Options in detail in SEM-16-073, and responses provided little material new evidence. Responses were largely (but not entirely) correlated with self-interest. Since the SEM Committee set out its analysis of Options A to C in SEM-16-

073, the SEM Committee has decided to make 2021/22 a transitional year, which could mean that the Capacity Requirement is up to 150MW greater (about 2% of the Capacity Requirement)[36], which adds an extra security margin to all options, and hence weakens the arguments for a zero-crossing point at 20% above the Capacity Requirement.

6.4.21 The SEM Committee notes that Option A was popular with a number of capacity providers, and the TSOs. It is in the financial interests of capacity providers to advocate Option A. For any given supply curve, Option A will always deliver a greater capacity revenue to capacity providers, at any price between Net CONE[37] and zero. This is illustrated in Figure 10, which shows 3 different examples where the supply curve is horizontal, upward sloping and vertical in the region where it intersects with the different demand curves (bidding rules prevent a downward sloping supply curve). It illustrates that in all case, Option A delivers the greatest (in-year) capacity revenue to providers and the greatest (in-year) cost to consumers.

6.4.22 From the perspective of the TSOs, Option A minimises the risk of scarcity events, albeit at a higher capacity cost to consumers, at least in the auction year.

Figure 10: Comparative impact of curve option on capacity provider revenue

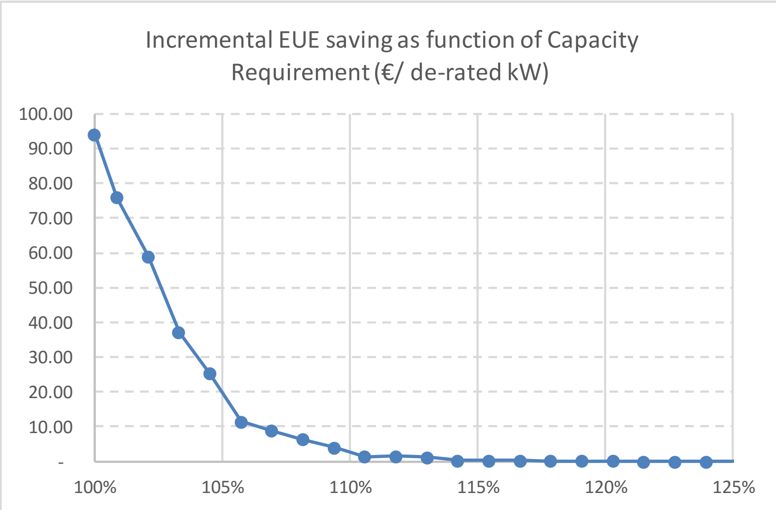


[36] This will depend on which demand scenarios turns out to be the Least Worst Regret (LWR) cost scenario, but experience to date has been that the LWR approach typically drives the requirement towards the higher end of the scenario range

[37] the curve are the same at a price above Net CONE

6.4.23 SEM-16-073 showed the trade-off between incremental capacity and the reduction in the value of Expected Unserved Energy (EUE). Figure 12 of SEM-16-073 showed this relationship for 2020/21 in MW terms. To make the point clearer[38], we have re-expressed this relationship as a percentage of the Capacity Requirement in Figure 11. It shows that there is very little additional value in reduced incidence of lost load beyond 110% of the Capacity Requirement (because the likelihood of lost load becomes so small).

Figure 11: EUE saving per incremental kW of de-rated capacity



6.4.24 Whilst recognising that there are other potential benefits from awarding a higher volume of Reliability Options in the first transitional auctions as discussed in SEM-16-073 (lower energy prices, more competition in subsequent capacity auctions), on balance the SEM Committee does not see the case for procuring up to 120% of the 2021/22 Capacity Requirement in 2018/19, plus additional capacity which may be necessary to satisfy locational constraints.

6.4.25 Given these considerations, the SEM Committee has decided not to place the zero-crossing point as high as 120% of the Capacity Requirement, and has decided to go for a hybrid option, without a point of inflection and with a zero-crossing point at 115% of the Capacity Requirement.

6.4.26 This is consistent with international experience, where few systems procure more than 115% of the Capacity Requirement.

6.4.27 It is worth noting that this CRM Parameters decision is expressed in terms of percentages of the Capacity Requirement, rather than de-rated MW, since the Capacity Requirement remains to be finalised. An indicative Capacity Requirement presented in SEM-16-073 needs to be updated to reflect a number of subsequent updates / decisions including:

- The revised TSOs demand forecast scenarios set out in the 2017 Generation Capacity Statement (GCS)[39];

[38] And in the light of the decision to make 2021/22 a transitional year too
[39] Previous numbers were based on the 2016 Generation Capacity Statement

- The SEM Committee's decision set out in SEM-16-082, not to add the reserve requirement to the Capacity Requirement initially, which removes approximately 450MW from the Capacity Requirement; and
- The decision to make CY2021/22 a transitional year, so that the Capacity Requirement for the first transitional auction will be based on the CY2021/22.

6.4.28 In conducting our analysis, the RAs have used a working assumption that the revised Capacity Requirement for the first transitional auction will be approximately 7,380MW, based on advice from the TSOs. However, the TSOs have yet to complete the revised estimate of the Capacity Requirement for the first transitional auction, based on the Least Worst Regrets scenario. The Capacity Requirement will depend in part on final de-rating assumptions (including the interconnector de-ratings which are published in the Initial Auction Information Pack), as well as other decisions set out in this document, such as the decision to make 2021/22 a transitional year.

6.4.29 Only once the final de-rating factors are calculated and approved by the SEM Committee (expected to be at the May SEM Committee meeting) will the TSOs be in a position to finalise the Capacity Requirement for the first transitional auction. Therefore, in this document, we will present our decisions on the shape and positioning of the demand curve in terms of percentages of the Capacity Requirement, rather than specifying the exact demand curve to be used in the first transitional auction in de-rated MW.

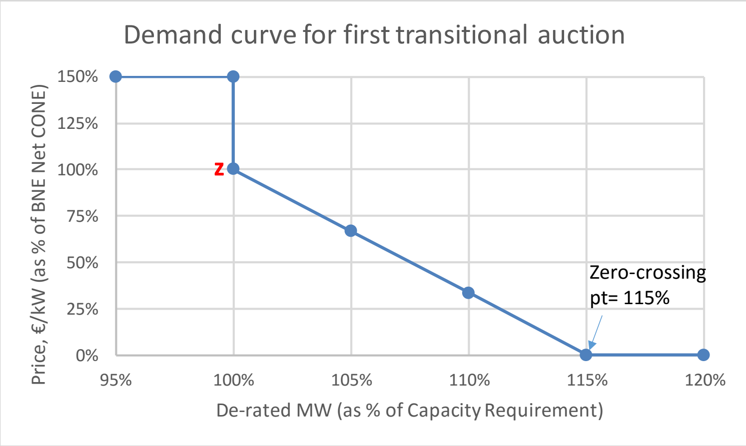
6.4.30 The provisional demand curve will be published in de-rated MW in the Initial Auction Information Pack to be published in early July 2017. This demand curve will then be adjusted for capacity which is not going to close, but has exercised its discretion not to bid into the auction. The final demand curve will then be published in de-rated MW terms in the Final Auction Information Pack.

SEM Committee Decision

6.4.31 The SEM Committee has decided to set the demand curve for the first transitional auction as follows:

- The curve will be horizontal at the Auction Price Cap (150% of the BNE Net CONE) between 0MW and 100% of the Capacity Requirement;
- The demand curve will be vertical at 100% of the Capacity Requirement between a price of 150% of BNE Net CONE and 100% of BNE Net CONE (point Z on the diagram below);
- The demand curve will be a straight-line slope between point Z and a zero-crossing point at 115% of the Capacity Requirement

Figure 12: Demand curve decision



6.4.32 For the avoidance of doubt:

- Prices are expressed in €/de-rated kW, with quantities expressed in de-rated kW or de-rated MW
- These values are **before** adjustments for capacity which chooses not to bid in the CRM auction, but is still expected to make a capacity contribution. The adjustment will result in a shift in the demand curve parallel to the x axis. For example, suppose that the Capacity Requirement is set at 7,000MW, then before adjustments, the zero-crossing point will be set at 115% x 7,000MW = 8,050MW. If 200MW of capacity chooses not to bid, the zero-crossing point will be at 115%x7,000MW – 200MW = 7,850MW[40].

6.5 LOCATIONAL PARAMETERS

Summary of consultation

6.5.1 Following the decision in the CRM Locational Issues decision paper (SEM-16-081) to recognise locational constraints in the CRM auction, and to represent them as nested capacity zones there is the need to define:

- The actual constrained zones to be used in the first transitional auction, including their geographic boundaries. The working assumptions have been that there are likely to be two nested zones, Northern Ireland and the Dublin area. However, this is only a working assumption, and the TSOs need to undertake further analysis to confirm the zones. Furthermore, the geographic boundaries of the Dublin zone, if it is to be a constrained zone, are yet to be determined;
- Locational capacity requirements parameters for those zones.

[40] i.e. as opposed to 115% x (7,000 -200)=7,820MW

6.5.2 In the CRM Parameters consultation paper (SEM-16-073), we discussed whether the local capacity requirements for the constrained zones should be represented by

- Introducing sloping local (zonal) demand curves (like we have done at an all-island level); or
- Simply specifying a minimum de-rated MW requirement for each zone.

6.5.3 It was the view, in SEM-16-073 that the SEM Committee does not propose to include the additional complexity of defining local demand curves, and intends to specify only a minimum de-rated MW for each zone.

6.5.4 Respondents were asked if they agreed that the cost/risk of implementing local demand curves (as opposed to a minimum requirement) outweighs the benefits.

Summary of consultation responses

6.5.5 The majority of respondents agreed with the RAs that the cost/risk of implementing local demand curves outweighs the benefits and instead a minimum MW capacity requirement should be applied. One respondent described how attempting to implement locational demand curves would over complicate the auctions.

6.5.6 One respondent suggested that the inclusion of local demand curves is unnecessary as long as the auction format option B remains in place. Another respondent described how the elasticity of demand should be reflected in the combined demand curve for Ireland and Northern Ireland. This respondent stated that this does not preclude the introduction of such local demand curves at a later date if deemed appropriate; however, for the transitional period, they believed that one demand curve is sufficient.

6.5.7 One respondent stated that it was difficult to comment given the scarcity of information provided, however it was suggested that adopting Option A for the overall demand curve may reduce the volume of locational contracts that are needed.

SEM Committee Responses

6.5.8 The responses reinforced the SEM Committee's view that, at least for the first transitional auction, the cost/risk of implementing local demand curves outweighs the benefits and instead a minimum capacity requirement should be applied. Therefore, for the first transitional auction, the SEM Committee only intends to have a minimum de-rated MW requirement in constrained zones. The SEM Committee will then review the case for having zonal demand curves in the subsequent transitional auctions in light of the experience of the first auction.

6.5.9 As discussed in the CRM Decision on Locational Issues (SEM-16-081, para 4.5.1), the SEM Committee has not made a decision on whether to include locational capacity constraints in the first T-4 auction (for CY2022/23) and may consult on whether to implement zonal demand curves as part of that decision. Different factors may apply in respect of a T-4 auction, where new entry is significantly more likely, and if constraints are expected to be more enduring (any inclusion of them in a T-4 auction would be an indication that they are).

SEM Committee Decision

6.5.10 The SEM Committee has decided not to implement zonal demand curves. Therefore, the key locational parameters for the first transitional auction will be:

- The zones (how many, how each is defined geographically)[41]; and
- The minimum MW of Reliability Option to be awarded in each zone.

Next steps

6.5.11 The SEM Committee has asked the TSOs to develop a methodology for defining the zones and for defining the minimum MWs in each zone. The SEM Committee plans to consult on that methodology in mid-April 2017, and publish a decision on that methodology in early July.

6.5.12 The TSOs, as the CRM Delivery Body will then publish the actual zones in the Initial Auction Information Pack in early July, following approval of their analysis by the SEM Committee. However, the minimum MW required in each zone will be withheld to limit gaming opportunities until the Final Auction Information Pack is issued 2-3 weeks before the first auction.

[41] in much of the discussion so far, the working assumption is that there will be two constrained zones, Northern Ireland and the Dublin area, but this is only an assumption, and the boundaries of the Dublin area have not been defined

7 NEW BUILD, TERMINATION FEES AND PERFORMANCE BONDS

7.1 INTRODUCTION

7.1.1 In the CRM Parameters consultation (SEM-16-073) we consulted on the following potential parameters:

- **New Capacity Investment Rate Threshold (NCIRT):** The €/MW financial threshold which a bidder must be investing to qualify for a multi-year Reliability Option (of up to 10 years). In previous CRM consultation and decision documents, we have referred to this parameter as the New Investment Threshold. This parameter is now termed the New Capacity Investment Rate Threshold in the Capacity Market Code (CMC) draft;
- **The schedule of Termination Fees for New Build capacity.** It is worth noting that any uncommissioned capacity counts as New Build and will be subject to the schedule of Termination Fees, regardless of whether it meets the NCIRT or not, and regardless of whether it is awarded a multi-year Reliability Option**;**
- **Whether Termination Fees should be applied to other capacity**, and if so, what the schedule of Termination Fees should be; and
- **Performance Bonds**.

7.2 NEW CAPACITY INVESTMENT RATE THRESHOLD

Consultation Summary

7.2.1 In CRM Decision 2 (SEM-16-022), the SEM Committee decided that:

- Any “plant requiring significant new investment” will be able to fix its Reliability Option fee for multiple years (which was fixed as a maximum of 10 years in CRM Decision 3, SEM-16-039);
- To be classified as “plant requiring significant investment”, the plant will need to demonstrate that *inter alia*, investment is above a €/MW threshold.

7.2.2 The current Capacity Market Code draft issued for consultation (SEM-17-004a) has termed this threshold the New Capacity Investment Rate Threshold (NCIRT).

7.2.3 The threshold will be set in €/MW and converted to a £/MW at the prevailing forward exchange rate to be published prior to the start of the Qualifying Window for the relevant auction.

7.2.4 The CRM Parameters consultation (SEM-16-073) considered how to set the appropriate level for the NCIRT, and proposed that the NCIRT be set at 50% of the gross Best New Entrant (BNE) investment cost[42], approximately €310/de-rated kW. Note that the gross BNE investment cost is a measure of the total gross amount that a Best New Entrant plant needs to invest, whereas Gross CONE and Net CONE are annualised value of the gross BNE investment cost[43], annualised over of 20 year BNE economic life.

7.2.5 This number was proposed, as it was expected to accommodate most genuine investment (since the BNE reference plant has specifically been chosen as a plant with low investment costs) and because it is broadly in line with international norms.

Summary of consultation responses

7.2.6 A number of respondents agreed with the proposal to set the NCIRT at 50% of the gross BNE investment cost, saying they believed it was appropriate and in line with other capacity auctions.

7.2.7 The majority of respondents did not agree with the level of the proposed NCIRT, considering it too high and disallowing refurbishment:

- One respondent stated that it is too heavily weighted for new plant and rules out enhancement or refurbishment;
- Another respondent argued that the factor of 50% is not well justified and suggested that the resulting cost is nearly double the rates in GB, and argued that there is risk of higher costs for consumers;
- One respondent argued that setting the investment threshold at this high level means offering longer-term contracts to some bidders, but not others, is a difference in treatment that lacks any objective justification, and distorts competition. This respondent argued that if longer term contracts allow new entrants to achieve a lower cost of capital than existing plant, the market will be distorted in favour of inefficient new entry.

[42] This is the gross investment spend, not an annualised value unlike Gross CONE and Net CONE
[43] In the case of Net CONE, net of infra-marginal rent and ancillary services

7.2.8 Some respondents wanted the SEM Committee to revisit its decision, made in CRM Decision 2 (SEM-16-022) not to introduce a specific category for refurbishment / upgrade investment, and to have low investment thresholds for these categories. For instance:

- One respondent argued that the effect of this high threshold exacerbates the impact of the lack of provision for 'sunk' cost recovery within the NGFC calculation, and effectively drives any refurbishing plant to recover investment costs in a single year, while a 'new' plant has 10 years to recover the equivalent investment;
- One respondent argued that the proposal discriminates and forecloses the market for the efficient refurbishment of existing low cost plant, and suggested the inclusion of a refurbishment contract, with a tenor of 5 years and an investment threshold of circa €120-€140/kW;
- Another respondent also suggested that there should be additional investment categories, and stated that the two markets referenced have additional categories to account for refurbishment such as incremental capacity and environmental compliance.
- Another respondent suggested a second lower threshold no greater than 10% of the gross investment cost of the BNE plant should be introduced, along with provision for exceptions below this threshold on a case-by-case basis;
- Another respondent suggested a minimum value is selected between the costs of building New Capacity and the costs of upgrading an existing unit, stating that they did not believe setting a 'discount factor' of 50% to approximately align the investment rate threshold with international precedent is appropriate.

7.2.9 One respondent recognised that there is only one threshold, and suggested a lower percentage of gross BNE costs is selected (40%) that more closely matches the ISO NE benchmark, and further argued that it was appropriate given the tenor of the I-SEM contracts are more comparable to ISO NE than GB.

7.2.10 One respondent stated the SEM Committee has not provided any evidence on the costs of lifetime extension works for existing plant and that analysis should be reflected in the threshold.

SEM Committee Response

7.2.11 The SEM Committee points out the gross BNE cost is the investment that a **low cost** new investor on a greenfield site would be expected to make. A low-cost investor on an existing site may be able to save some cost e.g. by reusing the site including electricity and water connection assets[44]. However, we would expect most genuine new build capacity to have a gross investment cost at least equal to the gross BNE cost.

7.2.12 The reasons for not having a refurbishing category eligible for multi-year Reliability Options were set out in CRM Decision 2 (SEM-16-022), and the SEM Committee does not intend to revisit this arrangement at this point in time. However, the SEM Committee recognises that proposals set out in the CRM Parameters consultation paper may not give sufficient incentive to refurbish/upgrade plant. On balance, the SEM Committee has decided to implement two proposals to incentivise efficient refurbishment:

- As discussed in Section 6.3, a refurbishing plant will be allowed a proportion of their investment costs into their Unit Specific Price Cap (USPC) applications. Our proposed treatment reflects an approach adopted in the PJM capacity market; and
- We are persuaded that it is appropriate to reduce the threshold to 40% of the gross Best New Entrant cost. The proposal to set the New Capacity Investment Rate Threshold at 50% of the gross BNE cost was slightly on the high side, particularly given recent movements in exchange rates. At this revised level, it is likely that any significant capacity, even on a brownfield site, should be able to bid for a Reliability Option of up to 10 years.

7.2.13 As illustrated in Table 5 below, we have re-estimated the international benchmarks for "substantial financial commitment" thresholds, and 40% of the gross BNE cost appears in line with these benchmarks.

Table 5: International benchmarks of substantial financial commitment

GB 2015 T-4 Auction (in 2014/15 prices for 2019/20 delivery)				
Financial thresholds…	GBP/kW	EUR/kW at Dec 2015 x-rate	EUR/kW at 7 Feb 2017 x-rate	07/02/2017 value as SEM gross BNE %
New build capacity	255	352	295	41%

ISO NE Current (22/07/2016)				
Financial thresholds…	USD/kW	EUR/kW at 22/07/2016 x-rate	EUR/kW at 07/02/2016 x-rate	07/02/2017 value as SEM gross BNE %
Repowering capacity	296	269	277	39%
Incremental capacity	296	269	277	39%

7.2.14 These proposals should ensure that genuine new build capacity can obtain a multi-year Reliability Option. Plant which is undertaking minor upgrades which require an investment of less than 40% of gross BNE cost will not meet the threshold to obtain a 10-year Reliability

[44] BNE cost calculation from SEM-15-059 indicate that this cost account for about 15% of the BNE cost

Option. However, it will be able to bid these costs into its USPC bids and may recover them on a year by year basis.

7.2.15 The SEM Committee recognises that this means that existing, refurbished and new capacity will not be competing on an entirely equal basis, but this is an inevitable consequence of the need to give new plant multi-year contracts to finance their investment. Those US markets (e.g. ISO New England, PJM) and GB, which have made a similar decision to award multi-year contracts have also introduced different treatments, with the consequence that the existing, refurbishing and new capacity have different contract lengths, and/or different bid caps in these markets too.

7.2.16 One respondent stated the SEM Committee has not provided any evidence on the costs of lifetime extension works for existing plant and that analysis should be reflected in the threshold. The SEM Committee does not agree. The SEM Committee's aim in setting the NCIRT is to decide what constitutes as a level of financial investment reasonable for an investor to bear without a multi-year contract, and what level of risk is appropriately mitigated by a contract of up to 10 years. The point is not to relate this to particular projects. International benchmarks provide the best available evidence, which is why we have placed significant weight on them.

7.2.17 As part of the SEM Committee's decision on the Fixed Cost of a Best New Entrant Peaking Plant (SEM-15-059), the SEM Committee estimated the gross BNE investment cost as €132.688m. To inflate this 2016 value to 2017 the SEM Committee used an inflation rate of 1.6% (SEM-16-044). We have used the current annualised rate of inflation of 2.6% to further inflate the value to Capacity Year 2018/19, compounding this value to 4.59% since we need to adjust for a 1.75 year period between calendar year 2017 and Capacity Year 2018/19. Therefore, the total estimated gross BNE investment cost for 2018/19 is €141.00m for the reference 195.7 nameplate MW plant, i.e. an equivalent of €720.51/nameplate kW. Based on a de-rating factor of 95% for the BNE reference plant, this equates to €758.44/de-rated kW. Therefore for the first transitional auction, 40% of the gross BNE investment cost will be €303.37/de-rated kW, and we will approximate the NCIRT at €300/de-rated kW. Further details on relevant adjustments made to the SEM BNE are set out in section 7.2.

SEM Committee Decision

7.2.18 The SEM Committee has decided to set the Termination Fee at 40% of the gross BNE cost. For the first transitional auction this will be set at €300/de-rated kW.

7.3 TERMINATION FEES FOR NEW BUILD CAPACITY

Consultation Summary

7.3.1 CRM Decision 2 (SEM-16-022) noted that it is important that a new build project be required to pay a Termination Fee if it fails to deliver capacity, and that it should provide a Performance Bond in advance of the auction as surety that it can cover the Termination Fee. The Termination Fee will be payable if the project:

- Fails to achieve the Substantial Financial Completion[45] milestone by the given date; or
- Fails to achieve Substantial Completion[46] by the Long Stop Date; or
- Submits false or misleading information in the pre-qualification process.

7.3.2 Furthermore, in CRM Decision 2 the SEM Committee decided that the level of Termination Fee should rise progressively over the lifetime of a project to build new capacity. Specifically, it stated that:

- It should start at a low level and increase progressively through the lifecycle of a project. This has the attraction of providing incentives for failing projects to declare their failure early – and so avoid increased Termination Fees; and
- It should reach its full level just before the last routine event through which alternative capacity could be procured to replace a failing project. This will be the point at which the capacity requirement is set for the T-1 auction covering the first year in which the relevant plant could (if commissioned) receive option fees.
- The "full level" of the Termination Fee should be set based on analysis of:
    - The cost to consumers of undelivered capacity;
    - The level of liquidated damages available from a typical EPC[47] Contract; and
    - The level of penalties for undelivered capacity to which an existing unit would be exposed.

45 The definition of Substantial Financial Completion was being developed within the Rules Working Group, but requires that all the Major Contracts and financing arrangements are in place and evidence of this is provided, and that the Party has sufficient financial resources available to it to meet the Total Project Spend
46 The definition of Substantial Completion is being developed within the Rules Working Group, but requires that the works are complete, the new capacity has undergone commissioning testing and has achieved Operational Certification (under the relevant Grid Code) that confirms the ability to deliver (after de-rating) 90% of its awarded capacity
47 Engineering, Procurement and Construction Management Contract

7.3.3 Indicative numbers were provided within the CRM Decision 2 of the cost to customers of undelivered capacity (€47/kW to €55/kW), which were recognised as broad brush estimates based the only data available from the TSOs at that time.

7.3.4 Since the CRM Decision 2 was published, the TSOs have provided updated analysis of the cost to customers, and we have looked at international benchmarks. Both were outlined in the parameters consultation paper, to help determine the maximum level of fees that might be consistent with attracting investment.

7.3.5 The favoured approach, proposed within the parameters consultation paper, aimed to be an appropriate balance between simplicity, promoting the right incentives and not prohibitively deterring investment. The following Termination Fees were proposed for new capacity:

- Termination at any time after the auction but more than 13 months before the start of the Capacity Year: €10/kW. A T-1 auction may occur between 2 and 13 months prior to the start of the Capacity Year;
- Termination between 13 months before the start of the Capacity Year and the start of the Capacity Year: €30/kW;
- Termination after the start of the Capacity Year: €40/kW.

7.3.6 Feedback was sought as to the appropriateness of the above schedule of termination fees.

7.3.7 CRM Decision 1 decided that Implementation Agreement would be required for new capacity, and CRM Decision 2 tied the payment of Termination Fees to the termination of an Implementation Agreement. The implication of these decisions is that all new capacity would be subject to Termination Fees regardless of whether it meets the substantial financial commitment criteria, and regardless of whether it is awarded a multi-year Reliability Option.

7.3.8 It is worth noting that the draft version of the Capacity Market Code issued as SEM-17-004a applied Termination Fees to all new capacity, with new capacity defined as any uncommissioned capacity. The draft of the Capacity Market Code was developed (based upon CRM policy decisions to date) by the TSOs through consultation with the Rules Working Group, but was issued on 12 January 2017, i.e. after the CRM Parameters consultation closed. In principle, this Capacity Market Code draft applies Termination Fees to all uncommissioned capacity, including:

- The incremental capacity delivered as a result of a refurbished / upgrade to generation, regardless of whether it has applied for or been awarded a multi-year Reliability Option. In the case of existing capacity market units, which had previously been commissioned, the Termination Fee only applies to the upgraded capacity;
- Any incremental DSU capacity which has not been previously "commissioned", regardless of whether that incremental DSU capacity was delivered via back-up generation, or via pure load reduction without any back-up generation being commissioned. We note however, that the definition of what constitutes "commissioning" in respect of a DSU was not fully defined in SEM-17-004a.

Summary of consultation responses

7.3.9 A number of respondents were in favour of a progressive Termination Fee structure (i.e. as proposed in SEM-16-073), agreeing with the time-weighted nature of the penalty, with penalties increasing for failure to deliver the closer to delivery one gets. One respondent described how Termination Fees set at an appropriate level are essential for new build capacity projects, as a deterrent to capacity hoarding. Respondent generally agreed that a balance needed to be struck between the termination fees providing incentive to delivering the capacity or terminating the contract with sufficient notice, and not being prohibitive to new investment. However, one of these respondents stated that it was difficult to gauge whether the proposed Termination Fees achieve this objective, and others did not opine as to whether the proposed schedule achieved that balance.

7.3.10 One respondent felt the Termination Fee schedule was too high and argued that the resulting bond level is set very high and will present a barrier to entry if participants are not able to pass through their potential liabilities and may cause participants to reflect any residual exposure in an explicit premium to the EPC or reflect any exposure in auction bids submitted.

7.3.11 By contrast, other respondents argued that the schedule of Termination fees (or at least parts of the schedule) were too low. For instance:

- One respondent also stated that the proposed first schedule of Termination Fees (i.e. €10/kW) is too low and would not discourage speculative bidders, which could in turn risk skewing the capacity market price. The respondent suggested basing the Termination Fee off the cost of procuring replacement capacity closer to the delivery date
- Another respondent stated their preference for fees to be set around £10/kW (c. €12/kW) higher, to recover a higher proportion of the cost of non-delivery to consumers and to ensure that developers are less likely to receive surplus funds from liquidated damages in the event that a project fails to deliver
- One stated that the full Termination Fee should apply before the start of the Capacity Year as this would better reflect (and offset) the costs associated with the non-deliver of this capacity.

7.3.12 One respondent argued that different sized unit should be subject to different Termination Fee schedules. They stated that they were not convinced that there is a linear relationship on the size of the failed delivery of capacity to the impact on the consumer (greater-than-pro-rata-to-MW-size).

7.3.13 A number of respondents argued that Termination Fees should recognised that the main reason for delay on project development in Ireland has been due to non-delivery of electrical or gas connection infrastructure outside the direct control of the EPC contractor. It was stated that developers would therefore need to be protected for delays outside of their control before Termination Fees crystallise or Bonds/Letters of Credit are called.

7.3.14 One respondent expressed concerns that there was not a clear process outlining how the Termination Fee should be set and how it should change with the market and market dynamics.

SEM Committee Response

7.3.15 The SEM Committee considers that the schedule of Termination Fees set out in SEM-16-073 strikes the right balance between incentivising new capacity to deliver against it Reliability Option commitments, and not deterring investment. The SEM Committee is keen to adopt the lessons learnt from the GB capacity market experience, where the relevant authorities saw the need to increase fees (to the levels set out in SEM-16-073) following the failure of some capacity to deliver on commitments made in early auctions. The SEM Committee feels that the approach to developing the schedule, and the factors considered were laid out in full in SEM-16-073.

7.3.16 The SEM Committee notes the suggestion that Termination Fees should be capped at the Annual Option fee. The SEM Committee sees merit in capping Termination Fees at such a level for DSUs (in order to incentivise environmentally friendly load reduction), but does not consider this approach to be more generally appropriate. The SEM Committee has decided not to cap the Termination Fees at the Annual Option fee for new capacity because:

- In the case of plant which exceeds the NCIRT, it may earn the Annual Option fee for 10 years. As we discuss in Section 7.4 **Error! Reference source not found.**, we do not propose at this time to apply Termination Fees to existing capacity, which strengthens the weight of this point; and
- The Annual Option fee bears no necessary relationship to the level of consumer detriment, if the capacity is not delivered, and consumer detriment is a key determinant of the Termination Fee.

7.3.17 The SEM Committee notes that some recipients have suggested that fees be set at a higher level initially to deter speculative bidders. However, the SEM Committee is not inclined to increase the Termination Fee at an early stage in the project at this stage, and notes that:

- To qualify to be able to submit a bid, a potential Capacity Provider needs to make significant investment. For instance, it is necessary to have planning approval, and to have signed a connection agreement. This is likely to deter totally speculative bids.

- At least for the first transitional auction, given the proposed timings, any New Build winner would immediately be subject to a Termination Fee of at least €30/kW.

7.3.18 The SEM Committee notes the point that the impact of non-delivery of a large unit on consumers may not be the same in €/kW terms as the non-delivery of a small unit of capacity. However, the SEM Committee does not propose to introduce lower Termination Fee schedules for small de-rated MW units because:

- The Termination Fee schedule for all units is significantly less than the likely consumer detriment. As discussed in SEM-16-073, setting Termination fees at a level that fully reflected consumer detriment would significantly adversely impact investability;
- Estimates of the impact on consumer detriment are not precise enough to warrant it; and
- At this stage, for the first transitional auction we are not expecting significant new entry, and as we discuss in Section 7.4, we are not proposing to apply Termination Fees to existing capacity.

7.3.19 The concern regarding delays outside the direct control of the EPC contractor was previously raised by respondents to CRM Consultation 2 (SEM-15-014). In CRM Decision 2 (SEM-16-022) the SEM Committee stated, "*The SEM Committee notes the concerns of some respondents about external events, outside a project's control, that could delay achievement of a milestone against which a termination condition exists. The SEM Committee have considered the events identified by respondents, and does not believe that they merit any extension to the milestones*". The SEM Committee sees no reason to revisit this decision.

SEM Committee Decision

7.3.20 The SEM Committee confirms that it has decided to set the Termination Fees for new (incremental) capacity in accordance with its proposals set out in SEM-16-073, i.e. as follows:

- Termination at any time after the auction but more than 13 months before the start of the Capacity Year: €10/kW. A T-1 auction may occur between 2 and 13 months prior to the start of the Capacity Year;
- Termination between 13 months before the start of the Capacity Year and the start of the Capacity Year: €30/kW;
- Termination after the start of the Capacity Year: €40/kW.

7.4 TERMINATION FEES FOR OTHER CAPACITY

Summary of consultation

7.4.1 SEM-16-073 considered whether it may be appropriate to impose Termination Fees and Performance Bonds on any other capacity where we might be concerned about the capacity delivery risk, including:

- Capacity which is incremental to existing capacity (and hence to a degree is unproven), but which does not meet the NCIRT or other criteria to qualify for a multi-year Reliability Option. We asked this question notwithstanding the presumption that Implementation

Agreements would apply to all uncommissioned capacity, not just capacity eligible for a multi-year Reliability Option;
- New / unproven DSUs; and
- Any existing capacity.

7.4.2 Since the deadline for SEM-16-073 consultation responses closed, the draft Capacity Market Code was issued for consultation, which

- Applies Termination Fees to incremental capacity to existing capacity market units and to “uncommissioned” DSUs;
- Does not apply to existing capacity (generators, interconnectors or DSUs), where the capacity is already commissioned. In principle, it would be possible within the drafting of SEM-17-004a, for a capacity market unit to commission first before entering an auction, and not be subject to Termination Fees.

7.4.3 SEM-16-073 noted that the impact on customers *if* these categories of capacity fail to deliver is the same as for new build capacity with significant investment and long development lead times, but arguably the delivery risk is lower.

7.4.4 We noted that in some cases, however, the delivery risk may not be trivial. There is a risk, particularly for T-4 auctions, that an existing capacity provider enters a capacity auction and takes a gamble on the amount of infra-marginal rent that it is in going to earn in four years. If closer to the time, infra-marginal rent forecast for that plant appears low, it could change its mind, and decide not to honour the Reliability Option that it has signed. This risk is partially mitigated by the Grid Code requiring Grid connected generators with Registered Capacity greater than 50MW to give 36 months’ notice of intention to close, and also the requirement to lodge collateral against difference payments.

7.4.5 We noted however, that in the case of new DSUs, we need to balance the risk to consumers with a desire to promote environmental objectives, and not unduly deter innovative DSU proposals.

7.4.6 The SEM Committee sought feedback on whether it is appropriate to place Termination Fees on other capacity, and if so, at what level.

Summary of consultation responses

7.4.7 There were a range of views, and views differ with respect to the appropriate treatment of existing capacity, incremental refurbished/upgraded capacity and DSUs.

Existing capacity

7.4.8 The majority of respondents stated that existing capacity should not bear Termination Fees because they are lower risk, have lower incentives for non-delivery as they have to post collateral against RO difference payments.

7.4.9 It was suggested that adding further Termination Fees for existing capacity will increase consumer costs, and may be unenforceable in several circumstances should a generator become insolvent and cease to trade. One respondent estimated that if existing capacity is required to pay Termination Fees according to the proposed schedule set out in SEM-16-073, it could lead to the industry collectively having to post a total of €675m in Performance bonds[48], which they argued is a disproportionate burden.

7.4.10 One respondent stated that there is no requirement under the current draft of the Capacity Market Code for existing capacity to post Performance Security or to pay a Termination Fee, suggesting that the capacity is already in existence so the risks are less. This respondent also stated that the Capacity Market Code does not allow voluntary de-registration of capacity that has been awarded capacity.

7.4.11 However, some respondents argued that any existing generator which is awarded a Reliability Option should be subject to some penalties:

- One respondent suggested that all capacity should be either a) required to post performance bond in the event that they disappear before the delivery year, or b) be required to still be bound by the difference payments arising. One respondent suggested that an existing unit should be liable for all Reliability Option difference payments for a given contract year even if it is terminated from the market during the year. They described how their obligation to payback could be managed through the TSC where the TSOs could retain the collateral needed, and draw down on it as and when difference payments occur.
- Another respondent stated that it is appropriate that capacity that does not meet the definition of new build should pay some sort of Termination Fee. There is a potential need for capacity providers in the CRM to have some stake in delivering their capacity beyond a simple loss of revenue and to avoid them perceiving a capacity award as a 'free option'.
- One respondent stated that they agreed with placing a Termination Fee on all capacity providers, but felt that the Termination Fees for existing generators must be taken into account with the Existing Capacity Price Cap (ECPC). This respondent suggested that the proposed Termination Fee is far too excessive for the limited associated risk as the exposure to the consumer is reduced because the capacity can be re-auctioned in the T-1 Auction.

[48] Once existing capacity has obligations in respect of a T-4 auction and all intervening years

Refurbishment / upgraded capacity

7.4.12 One respondent described how minor refurbishment or capacity upgrades do entail a slightly higher risk of non-delivery compared to existing capacity suggesting a Termination Fee proportionate to this position would be appropriate. This respondent also suggested that there should be no Termination fee on unproven DSU's, to promote environmental objectives and stimulate the provision of innovative DSU proposals. The respondent suggested that existing capacity should receive an obligation to pay termination fees for non-delivery, and that this could be set at 50% of the capacity payment they expect to receive in the delivery year.

7.4.13 One respondent stated that Termination Fees should apply to all new capacity and not just New Build (i.e. with a multi-year contract). Another respondent stated that existing plants that receive contracts should be forced to post some bond that is surrendered should they fail to deliver on their contract, while existing plants may not be required to undergo the same reporting requirements as new build units, the TSOs must ensure that the consumer is not exposed. One respondent stated that they do not believe the grid code closure notice period of 3 years presents a feasible risk mitigation measure.

Treatment of DSUs

7.4.14 There was a mix of views on the appropriate treatment of DSUs.

7.4.15 Of those who argued in favour of a different treatment for DSUs:

- One respondent stated that applying a Termination Fee to DSUs would be a significant barrier to entry for the demand side, suggesting that demand sites which terminate can be replaced by alternative demand side capacity easier.
- Another respondent stated that they were comfortable with the unproven DSU format, describing how it provides a price incentive for an aggregator to go out and recruit a portfolio of demand response to provide the service. This respondent stated that in many jurisdictions the aggregator is required to provide high level information and a business plan, and urged the RAs to provide more information on the TSOs requirements, stating that the current system would not be suitable.
- Another respondent suggested that the argument for "not proven" DSUs should not be addressed in a capacity auction and a separate mechanism should be implemented for non-proven technology. This respondent also stated that existing generators should not have a Termination Fee if it is mandatory to participate in the auctions.

7.4.16 However, a number of respondents argued that the CRM must be technology neutral and should not distinguish between existing capacity and DSUs, but should distinguish between unproven and proven capacity. A respondent stated that given the HLD decision to physically back Reliability Options, Termination Fees should be considered for any capacity which is unproven.

7.4.17 One DSU operator also urged the SEM Committee not to construct a regime which incentivised unreliable capacity (including DSUs) and made it clear that it is appropriate for DSUs to have incentives to deliver.

SEM Committee Response

7.4.18 The SEM Committee notes that in the draft Capacity Market Code published for consultation (SEM-17-004a), Termination Fees apply to all Awarded New Capacity at the same rate, and does not apply to existing capacity. However, the SEM-17-004a is a draft for consultation and the SEM Committee may require changes to that draft following the parameters consultation, or consultation on the SEM-17-004a itself.

Existing capacity

7.4.19 The SEM Committee is persuaded that it is not proportionate to subject existing capacity to Termination Fees and require it to lodge performance bonds. The risk that the plant will close after the first transitional auction is relatively low, and the potential impact on customers is mitigated by a number of factors:

- Existing capacity does not face the same project delivery risk as major new projects;
- Existing capacity will be required to lodge collateral against difference payments. The collateral will not be released if the capacity closes, and the collateral will be used to cover the Capacity Provider's difference payments regardless of whether the capacity closes or not;
- The potential impact on the industry if required to lodge Performance Bonds as a result is onerous. We have tried to validate the estimate of €675m produced by one respondent, and actually get a larger number;
- For the first transitional auction at least, the concern that existing capacity could enter the auction, win and then walk away is fairly limited. Firstly, closing after winning a T-1 auction would be a breach of Grid Code- which would have serious consequences for a licence holder, particularly one with other plant. Secondly, whereas with a T-4 auction there is a relatively long time for market conditions (and hence costs and infra-marginal rent estimates to change) between the auction and delivery, there is significantly less time between the T-1 auction and delivery. Therefore, the chances of a bidder basing its winning bid on assumptions which turn out to be false, and therefore deciding to close is reduced.

Refurbishment and upgraded capacity

7.4.20 The SEM Committee is minded to stay with the approach set out in the draft CMC consultation (SEM-17-004a) i.e. to apply the same schedule of Termination Fees to incremental uncommissioned capacity that results from refurbishments/upgrades as to new capacity. There is significant project delivery risk with refurbishments/upgrades (unlike with existing capacity which is not being refurbished), and it is proportionate to apply Termination Fees as a result.

7.4.21 However, there has been limited response on this specific point in the context of the CRM Parameters consultation, and the SEM Committee will finalise its decision in this respect in the light of any relevant feedback to the consultation on the CMC (SEM-17-004/004a).

DSUs

7.4.22 The SEM Committee considered the case for not applying a lower schedule of Termination Fees, or exempting DSUs from Termination Fees. The SEM Committee is keen to incentivise environmentally friendly DSU capacity which is delivered by demand reduction. However, on balance the SEM Committee has decided to apply the same schedule to uncommissioned DSUs as to other uncommissioned capacity. Key factors driving this decision are that the SEM Committee:

- Took note of the concerns, including those expressed by some DSUs, that arrangements should not incentivise unreliable DSUs;
- Notes that the consumer detriment from the non-delivery of x MW of DSU capacity is no different to the detriment from non-delivery of the same MWs of generation capacity;
- Agrees that generally, the approach to the application of Termination Fees should be technology neutral;
- Recognises that some generation is also environmentally friendly.

SEM Committee Decision

7.4.23 The SEM Committee has decided that existing capacity (already commissioned capacity) will not be subject to Termination Fees.

7.4.24 Termination Fees for new (uncommissioned) DSU capacity will be subject to the same schedule as for other uncommissioned capacity.

7.5 PERFORMANCE BONDS

Summary of consultation

7.5.1 Views were sought as to whether the Performance Bond that a bidder is required to put in place should cover 100% of the termination fee payable at any given time. This would mean that for new investment, as the Termination Fee rises over the course of the project up until delivery, the size of the Performance Bond should rise commensurately. Respondents were also asked if this approach should vary by type of capacity.

Summary of consultation responses

7.5.2 A number of respondents stated that the Performance Bond should cover 100% of the Termination Fee (provided termination fees are set at reasonable level); in order to ensure that the Termination Fee is recoverable.

7.5.3 Other respondents argued for lower Performance Bonds, for a variety of reasons, including:

- That the high bond level will present a barrier to entry if participants are not able to pass through their potential liabilities and may cause participants to reflect any residual exposure in an explicit premium to the EPC or reflect any exposure in auction bids submitted;
- That Performance Bonds are sufficient at €10/kW to prevent spurious bids into the capacity mechanism in the first place, and should be drawable if a new entrant does not increase the level of required bonding at the specific required time;
- One respondent who supported the indicative schedule of Termination Fees argued that the Termination Fee and the Performance Bond should be de-linked, and that the Performance Bond should not increase until after the T-1 auction, believing earlier increases would be unfounded;
- One respondent described how in a competitive bidding environment it will make it difficult to increase the bid to incorporate the bond and stay competitive.

7.5.4 Some respondents commented on the potentially different treatment of different capacity types, in how they may be required to lodge Performance Bonds. A number of respondents stated that it is not obvious why there would be variance in the calculation methodology for Performance Bonds across capacity types. However, as discussed above, some respondents argued that the application of Termination Fees (and by implication Performance Bonds) for new DSUs would be a significant impediment to their participation.

7.5.5 Some respondents argued that if Termination fees are required for existing capacity, they should not be required to post a Performance Bond, or that they should only be required to post a Performance Bond at a lower level. One respondent argued that Performance Bonds should not be required for existing capacity, which has existing assets. They stated that the imposition of a Performance Bond equal to 100% of the applicable Termination Fees will impose an excessive burden on all Capacity Providers. They estimated the overall requirement on the industry as to post performance bonds as being of the order of € 675m. This respondent stated that in determining the size of the performance bond a balance needs to be found between securing the supply of electricity and not discouraging new entrants from participating.

7.5.6 Another respondent suggested that instead of a Termination Fee for existing units, a form of penalty should apply if they terminate their contract whereby they are made liable to make difference payments until the end of their originally anticipated contract.

7.5.7 Some respondents argued that the size of the Performance Bond should be linked to variables other than the Termination Fee. For instance:

- One respondent suggested that the Performance Bond should be linked to the revenue that participant will receive from the auction instead of the Termination Fee. This respondent argued that it would be perverse for the participant to post credit for more than they would receive in the year, and suggested that the Performance Bond should be 50% of the annual fee;
- Another respondent stated that setting the Termination Fee above the Existing Capacity Price Cap (ECPC) is unfair to existing Capacity Providers who would have to pay more than they are eligible to receive.

7.5.8 One respondent requested the SEM Committee to review performance bond arrangements in relation to connections to the transmission or distribution systems to ensure that there is not double counting of bonding arrangements.

SEM Committee Response

7.5.9 The SEM Committee agrees that it is appropriate to set the Performance Bond to cover the level of the Termination Fee, in order to ensure that CRM Delivery Body can recover the Termination Fee. This approach is consistent with the approach taken in GB. It will also ensure that the Socialisation Fund is funded to cover the likely increase in difference payments that will result from the non-delivery of capacity.

7.5.10 The SEM Committee does not agree that it is appropriate to link the Performance Bond to the revenue that the participant will receive from the auction fee, rather than the Termination Fee. The purpose of the Performance Bond is to ensure that the Capacity Provider can meet the Termination Fee, with Termination Fees being set based on two factors, namely the cost to consumers and investability.

7.5.11 The SEM Committee does not intend to allow an existing generator to use its existing assets as collateral against Termination Fees on new capacity for two reasons:

- It provides the CRM Delivery Body with a number of practical problems if it needs to pursue a generation licensee for cash in lieu of a Termination Fee, and may also require the CRM Delivery Body to assess the residual value of assets and understand whether there any other creditors with priority calls on the asset;
- It potential provides existing generation asset owners with a source of competitive advantage, and could lead to an entrenchment of generators with existing high market shares.

7.5.12 The SEM Committee does not see any clear linkage between bonding arrangements for new connections and Performance Bonds to cover Termination Fees. Bonding arrangements for connections are generally there to ensure that the TSOs do not invest in connection assets which cannot then be recovered, whereas as the Performance Bonds discussed within this chapter are to cover Termination Fee which are designed to reflect (subject to investability criteria) the cost of additional unserved energy to consumers if the capacity is not delivered.

SEM Committee Decision

7.5.13 All capacity is required to post a Performance Bond to cover 100% of its Termination Fee exposure.

7.6 SUMMARY OF SEM COMMITTEE DECISIONS

7.6.1 The SEM Committee has taken the following decisions with regard to new capacity, Termination Fees and Performance Bonds

- The **New Capacity Investment Rate Threshold (NCIRT)** will be set at 40% of the gross BNE investment cost. For the first transitional auction, this will be €300/de-rated kW;
- **Termination Fees for New Capacity**: New Capacity, i.e. capacity which was not commissioned at the time of its Application for Qualification for the auction in question, will be subject to the following Termination Fee schedule:

- Termination at any time after the auction but more than 13 months before the start of the Capacity Year: €10/kW. A T-1 auction may occur between 2 and 13 months prior to the start of the Capacity Year;
    - Termination between 13 months before the start of the Capacity Year and the start of the Capacity Year: €30/kW;
    - Termination after the start of the Capacity Year: €40/kW.

- **Termination Fees for New Capacity** from a DSU will be subject to the same schedule as for other New Capacity;
- **Existing capacity** (i.e. capacity other than New Capacity) shall not be subject to Termination Fees;
- **Performance bonds:** All capacity is required to post a Performance Bond (referred to as Performance Security in the version of the CMC published for consultation as SEM-17-004a) to cover 100% of its Termination Fee exposure.

8 OTHER PARAMETERS

8.1 OTHER ISSUES

8.1.1 In this section, we discuss a range of other parameters, some of which were discussed in the CRM Parameters Consultation paper (SEM-16-073), others are parameters which result from the Capacity Requirement and De-ratings consultation (Consultation: SEM-16-051; Decision: SEM-082), and others have emerged from the CMC drafting in the Rules Working Group. The parameters are:

- Load following parameters for secondary trading, where we have deferred a decision, and we explain why we have deferred that decision;
- The negative tolerance percentage for DSUs (DECTOL); and
- Interconnector de-rating parameters;
- The Auction Offer Price Clearance Ratio, a parameter not created by any CRM policy papers, but developed by the CMC Rules Working Group.

8.2 LOAD FOLLOWING FOR SECONDARY TRADING

8.2.1 In CRM Decision 1 (SEM-15-103), the SEM Committee decided that Reliability Options will be “load-following”. The volume on which a capacity provider with 1MW of Reliability Option will be required to make difference payments on will be scaled back, where a scarcity event happens at times when load is less than the volume of Reliability Options. The decision to make the Reliability Option load-following has implications for secondary trading.

8.2.2 In CRM Decision 2 (SEM-16-022), the SEM Committee confirmed that plant should be able to physically back secondary trades using:

- Capacity that did not win a Reliability Option in the primary auction;
- The margin between “de-rated” and “nameplate” capacity for plant that are allocated Reliability Options (albeit each plant can only buy this capacity up to 10 weeks per year); and
- Margin between de-rated capacity and load following obligation: Capacity that lies between its adjusted load-following capacity obligation and de-rated capacity. This capacity for each Capacity Market Unit, which can be made available, will be determined on the basis of a profiling factor for the load-following capacity obligation parameter, now known as the Product Forecast Capacity Quantity Scaling Factor (FPFCQSF) in the drafts of the TSC and CMC.

8.2.3 In SEM-16-073 we consulted on the methodology for setting the FPFCQSF factor, which is one of the factors which governs the amount of capacity that a Capacity Provider can use to back a secondary trade. We received a number of responses, which are summarised in 0. However, subsequent to publishing SEM-16-073, it has become clear that the secondary trading platform to facilitate secondary trading of Reliability Options between Capacity Providers will not be ready for Day 1 of the I-SEM, notwithstanding the delay to go-live.

8.2.4 The SEM Committee understand that this secondary trading platform is not anticipated to go-live on Day 1The drafts of the CMC (including the draft of the CMC issued for consultation as SEM-17-004a) recognised the risk that the secondary trading platform would not be ready in advance of go-live (and Capacity Providers may want to begin secondary trading even earlier, as soon as the Reliability Options have been awarded), and that a fall-back solution may be necessary. The fallback solution described in Section M of the CMC draft involves a dummy "central counterparty", which can take on unlimited secondary trade[49], and there is no provision for a Capacity Provider to acquire Reliability Options through the secondary market.

8.2.5 Since during these interim arrangements, Capacity Providers cannot acquire a Reliability Option through the secondary market, there is no need to set FPFCQSF. The SEM Committee has decided to defer the setting of FPFCQSF until it is necessary, since experience of actual operation of the I-SEM may inform the setting of FPFCQSF.

8.2.6 Additionally, during the development of the CMC through the Rules Working Group process, the concept of a price cap for secondary trade bids and offers was introduced. In H.7.1.2 and H.7.2.2, of the version of the CMC issued for consultation as SEM-17-004a, the CMC refers to a price cap for secondary trade bids and offers which will be specified in the Secondary Trade Information Pack. It is likely that if this parameter exists in the signature version of the CMC, the SEM Committee will initially set this parameter value to a large number which does not bind. Since, as discussed above Capacity Provider to Capacity Provider Secondary Trading will not start with go-live, this will have no impact initially.

8.3 NEGATIVE TOLERANCE PERCENTAGE FOR DSUS (DECTOL)

Introduction and Background

8.3.1 The Capacity Requirement and De-Rating Methodology Decision (SEM-16-082) stated that DSUs will be de-rated on the basis of the System-Wide De-rating Curve, but will be permitted a negative tolerance to qualify below this level. This level will be set based on historic DSU availability, but adjusted for the changes to the I-SEM.

8.3.2 The negative tolerance (determined as DECTOL within the CMC) to be applied to DSUs is required as part of the Initial Auction Information Pack due to be published in early July. This

[49] although whilst the interim arrangements persist, since the dummy central counterparty is not physically backed, and to prevent gaming, a Capacity Provider which has acquired a Reliability Option in the primary market can only trade the Reliability Option on to the central counterparty where it has a planned outage as defined in the Grid Code.

paper provides a convenient opportunity for the RAs to set out their decision in respect of DECTOL and their associated reasoning.

8.3.3 The requirement for this determination was not set out in the CRM Parameters Consultation (SEM-16-073) as the SEM-16-082 decision was not complete at the time of its publication.

Key considerations

8.3.4 The analogue to Registered Capacity which applies to DSUs is the DSU MW Capacity, as defined in the Grid Codes. As set out in SEM-16-082, this is a maximum possible capacity which could be delivered but does not define a level of capacity obligation which a DSU would be capable of delivering. The actual capability of a DSU to contribute to capacity will depend on the Demand Sites from which it is composed. The DSU operator will take account of the characteristics of each Demand Site when establishing the level of capacity which can reliably be delivered.

8.3.5 Analysis of historic DSU data, comparing availability with DSU MW Capacity shows a range of potential values of DECTOL. This analysis also suggested that the composition of DSUs used in the SEM is unlikely to be appropriate for the I-SEM with its very different delivery incentives. This reduces the value of historic data in selecting an appropriate value of DECTOL to used.

8.3.6 Limiting the scope of a DSU to choose an appropriate level of capacity obligation offer in the CRM will place restrictions on the possible configurations of DSUs which could participate. This is undesirable against the **Competition** assessment criteria. There is no clear benefit to the market from requiring DSU to offer at least a minimum level of capacity, based on their DSU MW Capacity. CRM Decision 1 (SEM-15-103) only requires existing DSUs to qualify at any level for a capacity auction, so new DSU capacity can already choose not to qualify. Introduction of the I-SEM is likely to require changes to existing DSUs and this could easily require all (or many) DSUs to be created anew.

SEM Committee Decision

8.3.7 The SEM Committee have decided to set DECTOL equal to 100% for the first Transitional Auction.

8.4 INTERCONNECTOR PARAMETERS

Introduction and Background

8.4.1 The Capacity Requirement and De-Rating Methodology Decision (SEM-16-082) identified three values relating to the interconnectors which need to be determined by the RAs:

- the External Market De-Rating Factor (EMDF); and
- the Scheduled and Forced Outage Rates for the Interconnector Technology Class.

8.4.2 The methodology for determining these values is set out in SEM-16-082 and indicative values were given in that document based on the data available at the time of its publication. It was recognised that these values would need to be revised closer to the Capacity Auction to take account of more up-to-date inputs.

8.4.3 The three RA-determined interconnector values are inputs to the broader Capacity Requirement and De-Rating Methodology. The Capacity Requirement and De-Rating Curves form part of the Initial Auction Information Pack to be published in early July. As a result, new values for the three interconnector variables need to be determined now to feed into the TSOs process to determine their proposed values for the Capacity Requirement and De-Rating Curves which will subsequently be approved by the RAs and published.

8.4.4 The requirement for this determination was not set out in the CRM Parameters Consultation (SEM-16-073) as the SEM-16-082 decision was not complete at the time of its publication.

Key considerations

8.4.5 In determining the revised values for the Scheduled and Forced Outage Rates for the Interconnector Technology Class, historic outage data was used up to the end of 2016. This included all outages on both interconnectors over the last 10 years.

8.4.6 The value of EMDF was re-determined as described in SEM-16-082, but based on the following updated inputs:

- Demand and wind forecasts were taken from the GCS for 2017-2026
- The estimated Capacity Requirement was revised as follows:
  - Updated for 2017 GCS demand forecast
  - Updated for 2021/22 being the final Transitional Year, rather than 2020/21
  - Reserve requirement set to zero (as per SEM-16-082).

8.4.7 As set out in SEM-16-082, the value of EMDF for Great Britain should be determined on the basis of the *Slow Progression* and *No Progression* scenarios set out in the National Grid *Future Energy Scenarios 2016*. These scenarios have not changed since the Decision. The methodology required consideration of two different scenarios for potential exports from I-SEM at times of scarcity in GB: at 580MW and 950MW. Table 6 below gives the results of the analysis for the calendar years to be covered by the first Transitional Auction.

Table 6: EMDF values by scenario

Slow Progression	2018	2019
950MW export	60.8%	47.7%
580MW export	75.1%	62.8%
No Progression	2018	2019
950MW export	80.8%	92.0%
580MW export	88.7%	95.1%

8.4.8 Given the greater robustness of the Slow Progression scenario to accelerated closure of coal capacity in GB in the period covered by the first Transitional Auction, the SEM Committee have focused on that scenario in setting the value of EMDF.

8.4.9 As set out in SEM-16-082, the TSOs model will determine de-rating curves for the Interconnector Technology Class based on the updated values for Forced and Scheduled Outage. For each interconnector, a base de-rated capacity will be determined from these curves based on the Aggregate Import Capacity of the interconnector. The final de-rated capacity of each interconnector will then be the product of this base de-rated capacity and the updated value of EMDF.

SEM Committee Decision

8.4.10 The SEM Committee have decided to set the outage rates for the Interconnector Technology Class, based on historical data up to the end of 2016 as follows:

- Forced Outage Rate: 6.9%
- Scheduled Outage Rate: 3.7%

8.4.11 The SEM Committee have decided to set the EMDF for Great Britain to 60% for the first Transitional Auction.

8.4.12 Based on estimates of the interconnector de-rating curves, derived from the model curves shared by the TSOs at the workshop on 29 September 2016, the SEM Committee has determined an indicative value for the de-rating of a 500MW interconnector to be approximately 45%. This value is only an estimate and a value based on the actual de-rating curves for the interconnectors will be included in the Initial Auction Information Pack.

8.5 AUCTION OFFER PRICE CLEARANCE RATIO

8.5.1 In F.8.4.4 and F.8.4.5 the concept of the Offer Price Clearance Ratio has been created (in square brackets). This multiplies the Auction Clearing Price and any PQ pair below this price will be cleared to its scheduled quantity. The scheduled quantity comes from the unconstrained auction in F.8.3 and the clearing related to resolution of local capacity constraints. F.8.4.5 suggests the default value is 0%, i.e. nothing clears automatically but must follow the normal rules. This parameter is not used by the Interim Solution for Local Capacity Constraints, but will be set at zero until such time as the SEM Committee decides otherwise.

9 NEXT STEPS

9.1.1 A number of the parameters discussed in this document remain to be finalised, with pending inputs from the TSOs. Where relevant, the TSOs or the RAs will update parameters and submit them for approval to the June SEM Committee. These approved parameters will be published in the Initial Auction Information Pack to be issued in early July, when market participants can begin submitting their Qualification applications. A full list of the parameters values to be published is set out in Table 7. Table 7 also shows which of these parameters we expect to be updated further, why and when then updates will be provided. The two key points at which updates will be issued are in the Initial Auction Information Pack in early July and with the issue of the Final Auction Information Pack, 2-3 weeks before the auction.

Table 7: Parameter updates

Parameter value to be included in Auction Information Pack	Whether updates expected and why
Auction timetable	To contain more detail than timetable published in Section 2.6, but no changes to dates anticipated at this stage.
Full and Partial ASP values	No changes before go-live. Timeline for transition of Full ASP to full VoLL based value not yet determined. ASP provisions set out in TSC and subject to TSC change control processes.
Strike Price formula	No planned changes.
Strike Price: DSU floor	Set at €500/MWh in nominal terms in Section 5.2 of this document. No planned changes.
Fuel, carbon and exchange rate indices	To be published in Initial Auction Information Pack, and not expected to change thereafter unless CRM Delivery Body advise that index no longer exists/relevant.
Carbon intensity factors	To be published in Initial Auction Information Pack, and not expected to change thereafter unless index changes result in the choice of a change in carbon intensity.
Transport adders	To be published in Initial Auction Information Pack. Will change periodically as transportation costs change materially, and may change if delivery point of indices changes.
Annual and Billing Period Stop-Loss Limits	Annual Stop-Loss limit set at 1.5 x Annual Reliability Option Fee in SEM-16-022 and Billing Period Stop-Loss limits set at 50% of Annual Stop-Loss Limit in Section 5.3. No planned changes.
Termination Fee Schedule and Performance Security	Set in Section 7. No planned changes.
De-rating factor matrix (generators and DSU)	Updated estimates to be produced by TSOs based upon de-rating methodology using new ADCAL model. Updated values to be included in Initial Auction Information Pack. No further changes expected before first auction. Further consultation before first T-4 auction.
De-rating factors (interconnectors)	Indicative estimates published in Section 8.4. Estimates to be updated in Initial Auction Information Pack for changes to any updates to de-rating curves produced by TSOs as part of move to new ADCAL model.
Capacity Requirement	Indicative number of 7,380MW published in Section 6.4 of this

	document. Capacity Requirement will be re-estimated by TSOs applying Least Worst Regret approach to 2017 GCS demand forecast for 2021/22, taking account of updated de-rating factors. Revised value will be published in Initial Auction Information pack. No further updates prior to first auction. Capacity Requirement for subsequent auctions will take account of subsequent changes in demand forecasts.
Demand Curve	Specified in terms of Capacity Requirement and Net CONE in Section 6.4. Updated values to be published in terms of €/kW and de-rated MWs in the Initial Auction Information Pack. Demand curve to be updated for Qualification results (adjusted for any capacity which is expected to be available in 2018/19 but has not opted to bid) in Final Auction Information Pack.
Net CONE	Indicative value published in Section 6.2 of this document. Indicative value likely to be updated prior to issue of Initial Auction Information Pack for: • Updated de-rating factor for BNE reference plant; • Updated estimate of inflation. No further changes after issue of Initial Auction Information Pack. Further consultation before first T-4 auction.
Auction Price Cap (APC), Existing Capacity Price Cap (ECPC) and	Values are a function of Net CONE. Indicative values of APC and ECPC published in Section 6.2 & 6.3. Indicative value likely to be updated prior to issue of Initial Auction Information Pack for changes to Net CONE. No further changes after issue of Initial Auction Information Pack. Further consultation before first T-4 auction.
New Capacity Investment Rate Threshold (NCIRT)	Value a function of gross BNE investment cost per de-rated kW. Indicative value of NCIRT published in Section 7.2. Indicative value likely to be updated prior to issue of Initial Auction Information Pack for changes to de-rating factor for BNE plant and inflation. No further changes after issue of Initial Auction Information Pack. Further consultation on BNE reference plant for 2022/23 before first T-4 auction.
Capacity constrained zone geographic definition and minimum MW	The TSOs are developing a methodology paper to be issued for consultation in mid-April. The definition of the constrained zones will be published in the Initial Auction Information Pack. The minimum MW requirement will be published in the Final Auction Information Pack, as will the list of Qualified Capacity Market Units in each constrained zone.
Tolerance percentages for Generators and DSUs (INCTOL and DECTOL)	INCTOL and DECTOL set at zero for generators in SEM-16-082. INCTOL set at zero for DSUs in SEM-16-082 and DECTOL set at 100% of DSUs in Section 8.3. No changes planned.
Offer Price Clearance Ratio	Set at zero in Section 8.5. No changes planned.
Exchange rate conversion for auction bids	Northern Ireland capacity providers will submit bids in GBP, and these will be converted to EUR at the auction exchange rate for that auction. Northern Ireland paid-as-clear winners will be paid the EUR auction clearing price converted to GBP at the auction exchange rate. An indicative auction exchange rate will be included in the Initial Auction Information Pack, and the actual auction exchange rate will be fixed and published in the Final Auction Information Pack.

9.1.2 The SEM Committee has asked the TSOs to develop a methodology for defining the zones and for defining the minimum MWs in each zone. The SEM Committee plans to consult on that methodology in mid-April 2017, and publish a decision on that methodology in early July.

9.1.3 The Capacity Market Code has progressed through the TSOs Rules Working Group and was published by the Regulatory Authorities for consultation on 12 January 2017 (SEM-17-004). The Capacity Market Code consultation closes on 24 February 2017. The SEM Committee expects to make a decision on the Capacity Market Code in late May 2017 and issue the document in early June.

9.1.4 As set out in Table 7 above, further consultation will take place in advance of the first T-4 auction in regards to a number of the parameters for that auction. Consultation will also take place in respect to the inclusion of locational constraints within the T-4 auctions.

9.1.5 Consultation and decision papers will be published on the SEM Committee website: www.semcommittee.com

9.1.6 The Initial Auction Information Pack and the Final Auction Information Pack will be published by the TSOs as the CRM Delivery Body.

APPENDIX A ACRONYMS

APC	Auction Price Cap
ARA	Amsterdam-Rotterdam-Antwerp
ASP	Administrative Scarcity Price
BM	Balancing Market
BNE	Best New Entrant
CCGT	Combined Cycle Gas Turbine
CER	Commission for Energy Regulation
CIG	Carbon Intensity of Gas
CIO	Carbon Intensity of Oil
CMC	Capacity Market Code
CMU	Capacity Market Unit
CONE	Cost of New Entry
CRM	Capacity Remuneration Mechanism
CRF	Capital Recovery Factor
CY	Capacity Year
DAM	Day Ahead Market
DCCAE	Department of Communications, Climate Action & Environment
DECC	Department of Energy and Climate Change
DECTOL	Decrease Tolerance (also referred to as Negative Tolerance)
DfE	Department for the Economy
DSU	Demand Side Unit
DS3	Delivering a Secure, Sustainable Electricity System
EC	European Commission
ECPC	Existing Capacity Price Cap
EEAG	The Environmental and Energy State Aid Guidelines
EMDF	External Market De-Rating Factor
EPC	Engineering, Procurement and Construction Management Contract
ETA	Energy Trading Arrangements
EU	European Union
EUE	Expected Unserved Energy
EUR	EURO currency
FASP	Full Administrative Scarcity Price
FGD	Flue-Gas Desulfurization
FOR	Forced Outage Rate
FPFCQSF	Product Forecast Capacity Quantity Scaling Factor
FQMCCy	Capacity Charge Metered Quantity Factor
GB	Great Britain
GBP	Great British Pounds
GCS	Generation Capacity Statement
GUA	Generating Unit Agreement
HLD	High Level Design
ICE	Intercontinental Exchange

IDM	Intra-Day Market
IMR	Infra-Marginal Rent
INCTOL	Increase Tolerance
I-SEM	Integrated Single Electricity Market
ISO NE	Independent System Operator New England
LoLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LRMC	Long Run Marginal Cost
LWR	Least Worst Regret
MRP	Market Reference Price
MW	Megawatt
MWh	Megawatt hour
NBP	National Balancing Point
NCIRT	New Capacity Investment Rate Threshold
NGFC	Net Going Forward Costs
OCGT	Open Cycle Gas Turbine
PJM	Pennsylvania Jersey Maryland
POR	Primary Operating Reserve
PPB	Power Procurement Business
PQ	Price Quantity
PSO	Public Service Obligation
qSTR	Short Term Reserve Quantity (as defined in TSC)
RAs	Regulatory Authorities
RO	Reliability Option
ROI	Republic of Ireland
RPI	Retail Price Index
SEM	Single Electricity Market
SCR	Suppliers Contribution Rate
SO	System Operator
SOR	Secondary Operating Reserve
SP	Strike Price
SRMC	Short Run Marginal Cost
TOR	Tertiary Operating Reserve
TSC	Trading and Settlement Code
TSO	Transmission System Operator
UR	Utility Regulator
US	United States
USPC	Unit Specific Price Cap
VoLL	Value of Lost Load
WACC	Weighted Average of Cost of Capital

APPENDIX B CARBON INTENSITY FACTORS
APPENDIX C TRANSPORT ADDERS

A.1 Carbon Intensity Factors

Consultation Summary

A.1.1 In CRM Decision 3 (SEM-16-039) the SEM Committee decided to incorporate carbon intensity parameters, CIG and CIO into the Strike Price formula to recognise the existence of carbon pricing in European markets.

A.1.2 The Carbon Intensity parameters should be aligned with the carbon intensity of the reference fuel in the reference fuel index which will be proposed by the CRM Delivery Body for approval by the SEM Committee. In the case of natural gas, it is highly likely that the natural gas price index will be a GB NBP reference, and the value of CIG should reflect the carbon content of natural gas in the GB National Transmission system- the source of most gas burned in power stations in Ireland/Northern Ireland.

A.1.3 The choice of reference fuel index and carbon intensity parameters are being reviewed by the CRM Delivery Body and they will make a proposal for approval by the SEM Committee. The SEM Committee intends to make the final decision on CIG and CIO alongside the decision on the reference fuel index. In the meantime, feedback was sought regarding the approach to setting of gas or oil carbon intensity factors.

Summary of responses

A.1.4 A number of respondents agreed with the general approach outlined for using gas and oil Carbon intensity factors. One of these respondents agreed assuming that the gas/oil index choices will be NBP and Low Sulphur Fuel Oil, with these consistent with figures used by the RAs in the past and requested that the RAs confirm in their decision that this is what they will be in the future.

A.1.5 A number of responses stated that the reference fuel indices must be chosen before the carbon intensity factors can be defined. One respondent questioned the appropriateness of carbon intensity factors and transport adders for the RO strike price being set by a similar process to the Directed Contracts.

A.1.6 A number of respondents mentioned that the carbon intensity factors should reflect the introduction of Corrib gas. It was described how GB NBP flows have been substantially lower with the commissioning of a new Ireland entry point. One respondent stated that they did not understand why the RAs cannot request a carbon intensity figure from GNI as a better approximation.

A.1.7 One respondent stated that there seems to be no regulatory commitment to consult on the far more important question of the reference fuel index to be used. A number of respondents stated it would be appropriate to consult on the fuel indices with market participants actively trading in the market.

A.1.8 One respondent raised the issue of the cost of obtaining access to this fuel indices data, describing how if all participants need to source the data, the cost to the market as a whole may become significant. This respondent suggested fixing the Strike Price on an annual basis prior to the publishing of the Capacity Auction Information Pack.

A.1.9 One respondent stated that the cost implications of publishing such a reference fuel index price appeared to be causing issues with its selection, and this is of concern because it could potentially result in the chosen index changing year-to-year. With another respondent suggesting that whatever indices are chosen that they have a preference they come from a public source, and will endure for the shortest length of contract.

A.1.10 One respondent stated that the CRM Delivery Body is ill equipped to propose an appropriate reference fuel index. Another respondent stated it was difficult to understand why the CRM Delivery Body was charged with this task. A number of respondents suggested that the Reference fuel must be a daily index not monthly, otherwise will not reflect underlying price movements and volatility in energy market. One respondent cited it increases scheduling risk. One respondent suggested that the RAs should retain responsibility for the selection of fuel indexes, and should procure a recommendation from a consultant with the relevant expertise.

A.2 Transport Adders

Summary of consultation

A.2.1 CRM Decision 3 (SEM-16-039) confirmed that the CRM Delivery Body will calculate the fuel transport adders periodically, and submit them to SEM Committee for approval. The transport adders should be consistent with the delivery point for the relevant fuel index. For instance, if the delivery point for the chosen fuel index is ARA (Amsterdam-Rotterdam-Antwerp), a commonly quoted delivery point for North West Europe, the oil transport adders should reflect a difference in cost of delivery to a representative generation location in Ireland/Northern Ireland relative to ARA. Assuming that the quoted delivery point for the chosen natural gas index is NBP, the gas transport adder should include an adjustment for the cost of transporting gas from NBP to a representative generation location in Ireland / Northern Ireland. The adders should be defined after the reference indices have been chosen.

A.2.2 Indicative values were illustrated within the parameters consultation paper, based upon the current Directed Contracts process. Transport adders can differ between Ireland and Northern Ireland and it is proposed to use whichever is higher in setting the Strike Price. Feedback was sought regarding the approach for setting transport adders.

Summary of responses

A.2.3 A number of respondents agreed with the general approach of the inclusion of transport adders, and agreed that the higher of the values for transport to Ireland and Northern Ireland be used. One respondent cautioned that care needs to be taken when considering gas transportation costs in I-SEM generally in order to avoid distorting the market in gas generation.

A.2.4 A number of respondents stated that it is not clear why CRM Delivery Body is being charged with determining the transport adders. One of these respondents described how previously such costs were provided by some market participants on a confidential basis to the RAs. Another respondent stated that the transport adders are based on information that the TSOs would not have direct access to.

A.2.5 One respondent requested that the RAs specify how transportation costs will be built into the Strike price model, and stated that they assumed that the costs of gas presented reflect the cost of transporting gas from NBP to Moffat (£/therm) and then from Moffat to RoI (€/therm). A number of respondents repeated the point that the reference fuel indices must be chosen before the transport adders can defined.

APPENDIX D SUNK COSTS IN ECPC AND USPC

A.2.6 In this Appendix, the SEM Committee discusses the detail of the key criticisms made by stakeholders (principally generators) with regard to our proposal not allow sunk costs in Existing Capacity Price Cap (ECPC) or the Unit Specific Price Caps (USPC). We discuss these key criticisms under following headings in turn:

- The SEM Committee approach to ECPC/USPC/NGFC is appropriate and will deliver outcomes which limit the effect of market power, and deliver results which are consistent with a competitive outcome;
- The SEM Committee is not denying generators the opportunity to recover their total costs, whether constrained-on or otherwise;
- The approach does not infringe statutory obligation to have due regard to the need to ensure that generators are capable of financing their licensed activities;
- Disallowing sunk costs from existing generator bids will not discourage future investment;
- Disallowing sunk costs from existing generator bids will not discourage efficient plant upgrades;
- Our proposals are consistent with State aid considerations;
- Our proposals deliver required flexibility;
- We consider that our approach is consistent with international best practice.

Approach to ESPC, USPC and NGFC and impact on market power, and competition

A.2.7 We do not agree with the contention that our approach to setting ECPC and USPCs based on NGFCs is flawed or that it will harm competition. Furthermore, we reject the notion that our model is based upon "*a flawed interpretation of the theoretical ideal of perfect competition, which is not even applicable to sectors with long run, irreversible investments",* and this leads us to believe that "*prices that deviate from strict definitions of short run marginal costs can be consistent with competitive behaviour*".

A.2.8 On the contrary, our controls are designed to simulate the effect of competition in a situation in which we have the real-world problem of market power. The proposals are a pragmatic solution to addressing market power. They will ensure that the market delivers prices which, in the short term, reflect the current excess of capacity over the Capacity Requirement, whilst allowing them to rise in the longer term to the net cost of new entry or higher, when new investment is required.

A.2.9 There is currently an excess of existing capacity over the Capacity Requirement. As set out in the CRM Locational Issues consultation (SEM-16-052), the TSOs' 2016 Generation Capacity Statement indicates that there will be around 2,600MW of existing capacity in excess of the Capacity requirement, approximately a 35% excess. Given the subsequent decision not to double count reserves in the Capacity Requirement, this excess is probably closer to 40%.

A.2.10 In a fully competitive market, with such an excess supply, absent the exercise of market power (both unilateral and co-ordinated) we would expect a bidder to include only its forward-looking costs in its capacity market offer If it tried to include its sunk costs, it would substantially reduce its chances of winning in the auction, so we would expect it to include only those costs which are strictly necessary for its continuing operation in its bid.

A.2.11 However, market power may prevent the emergence of such a competitive outcome.

A.2.12 Our bid caps are designed to mitigate the effects of the market power in the CRM, where ESB has approximately 40% of the existing capacity[50], and to simulate what would happen if there was no market power exercised. Any bidder acting in conjunction with the next largest market participant could exercise co-ordinated market power, whether through explicit or tacit collusion (see section 4.3 of SEM-16-010). In CRM Decision 3 (SEM-16-039), the SEM Committee explained that given the scope for tacit collusion in the I-SEM CRM, the SEM Committee decided that it is appropriate to apply the bid controls to all existing generators, not just ESB.

A.2.13 A key consideration in setting the level of the controls is the real competitive environment, and it is our view of the real competitive environment rather than a model of perfect competition which has driven the proposed level of the caps. Several aspects of **real** competition are particularly relevant here, and are reflected in the approach to bid caps set out by the SEM Committee:

- The market is over-supplied. There is around 40% more existing capacity than the capacity requirement, which could be considered in part a legacy of a **real** lack of competition in the SEM Capacity Payment Mechanism;
- In such a **real** capacity market with excess supply but without market power, we would expect the price to fall close to avoidable cost (or variable cost in your, more general terminology), i.e. the level at which bid caps are pitched;
- There is a **real** issue with market power in the I-SEM capacity market, and as explained in CRM Decision 3 (SEM-16-039), this extends to **real** concerns with both unilateral and co-ordinated market power, which is why bid controls are applied to all bidders. The decisions made in the CRM Locational Issues Decision (SEM-16-081) also highlight the **real** local market power behind the expected Dublin constraint.

A.2.14 Once the current excess supply of old inefficient capacity has exited, we are expecting new entry to set the capacity price in most years- see paragraph A.2.22. In those years, prices will definitely diverge from the SRMC of supplying capacity, since new capacity will be allowed to bid 1.5 x Long Run Marginal Cost of Capacity (LRMC) and can be expected to bid at least its own LRMC.

A.2.15 Some generators may argue that it is only appropriate to constrain existing generators to bid at Net CONE, whilst there is a surplus of capacity (and market power persists), and that in the longer run, it is appropriate to allow existing generators to include sunk costs in their bids. However, it is likely that in years where no new capacity is required, existing capacity (which has the advantage of barriers to entry) will have a degree of market power. Without bid controls, existing capacity could bid up to Net CONE with little fear of losing in the auction, so that the auction would clear at or just below the total Net CONE even when no new capacity is required.

A.2.16 Now in years in which new entry is required, it may be that barriers to entry, such as the lack of available sites with planning permission and connection agreements, means that new build can win an auction by pricing significantly above Net CONE. This means that unless the SEM Committee continues to regulate bids of existing capacity to cover only NGFCs, on average the capacity market will clear significantly above Net CONE, i.e. in excess of a level which will allow efficient capacity to recover its total costs due to persistent market power. By this argument, regulation of existing bids is necessary to restrain market power in the longer run too.

[50] Refer to Table 1 of SEM-16-010 (CRM Consultation 3)

A.2.17 We also reject the suggestion that our proposed regime differs from best practice examples of energy markets, such as the US PJM market, the world's largest energy market with one of the best-established capacity markets. PJM has similar caps on energy market bids of those generators with market power in the energy market, and on existing and new generators in the capacity market.

Generator total cost recovery

A.2.18 It is not correct that the SEM Committee is denying generators the opportunity to recover their total costs.

A.2.19 Firstly, a new build generator can bid up to 1.5 its (total) Net Cost of New Entry, and can receive a contract which guarantees it that level of cost recovery for 10 years- which incidentally is much greater certainty than under the current SEM. Therefore, when new entry is required, the clearing price (and all generators who are successful in the auction will receive at least the clearing price) may rise to 1.5 x Net CONE in years in which new entry is required.

A.2.20 Some existing generators may not be able to bid at a level that covers their total costs, including sunk costs. However, that does not mean that the SEM Committee is denying them the opportunity to earn their total costs back, since their bids will not necessarily set the clearing price, and in-merit bids are paid-as-clear. Even without new entry, many existing generators will recover their total cost, if for instance:

- They are efficient in the energy market, are in-merit and earn significant infra-marginal rent;
- They have low fixed operating cost, i.e. significantly lower cost than the marginal unit in the capacity auction.

A.2.21 However, in the current over-supplied market some high cost plant, which is neither significantly in-merit in the energy market, or significantly in merit in the capacity market may not recover its total costs. However, that is exactly what we would expect in a competitive but unregulated market, absent market power.

A.2.22 Significant new entry is unlikely to be required in the next few years (except possibly to address locational constraints) since the market as a whole is over-supplied. However, we anticipate that in the medium to longer term, once the existing old inefficient plant has responded to the new exit signals contained within the I-SEM, there will be new entry setting the clearing price more frequently. New capacity will be required in order to replace existing plant at the end of its economic life or to meet load growth:

- Replacement plant. There are currently about 50 transmission connected thermal plant, although it may be that only around 40 are needed to meet the Capacity Requirement[51]. The BNE assumption about economic life of a plant is 20 years[52]. If there are 40 plant with an average life of 20 years, we would be replacing two old units with two new units in an average year, once excess capacity has retired. Even with normal statistical variation, we would expect this to mean that new capacity is required to replace old capacity on a frequent basis. This in part depends upon whether retiring plant is replaced by smaller

[51] Some of these are smaller than the BNE plant, others such as some CCGT are approximately double the MW of the reference BNE plant

[52] Some plant on the system is older, but may have remained on the system as the current SEM Capacity Payment System does not require old plant to compete directly with new plant for a fixed MW of capacity payments

BNE type units (the reference unit being 195MW of nameplate capacity) or larger CCGT units, which tend to be more like 400MW of nameplate capacity;

- Plant to meet load growth. However, in the medium term, once the excess supply has reacted to exit signals, it is anticipated that new entry will be required. In recent years, no new capacity has been required, because there have been insufficient exit signals for old capacity, and because there has been low load growth. However, according to the TSO's 2016 Generation Capacity Statement the all-island transmission peak demand is expected to grow by 130MW per year in the high growth scenario between 2017 and 2025 (50MW in the median growth scenario). Therefore, in the high growth scenario, we would expect to add the equivalent of a 195MW Best New Entrant unit about 2 in every 3 years just to meet load growth, whereas in the medium growth scenario we would expect to require one BNE unit to meet load growth every four year. Again, this depends in part on whether we expect new capacity to meet load growth to be satisfied by a larger CCGT (as per TSOs 2016 Generation Capacity Statement), or a smaller OCGT.

A.2.23 This analysis shows that once the current excess supply of old inefficient plant responds to exit signals, new units could set the clearing price a high proportion of the time. However, as discussed above this depends in part on whether replacement capacity, is on average larger CCGT units, smaller OCGT units or some other small units such as more renewables capacity[53], or other smaller units, such as smaller reciprocating engines.

A.2.24 Based on the above analysis, it is far from inconceivable that the market would clear on average at around the (total) Cost of New Entry, which would benefit existing plant as well as new plant.

A.2.25 We recognise that the proposals to require constrained-on generators to bid at cost in the balancing market (for complex bid offer data that cover non-energy actions and a small subset of energy actions) limit their ability to earn infra-marginal rent. However, we note that in a hypothetical situation in which there are no significant constraints, the generators which are constrained-on would not be running anyway, and would not be able to earn any infra-marginal rent either. Therefore, the regulation of the energy (balancing) market serves to take away the local market power conferred on constrained-on generators in the energy market by virtue of the transmission constraint.

A.2.26 Similarly, the regulation of out-of-merit bids in the capacity market serves to remove the local market power which may be conferred on a generator in the capacity market resulting from transmission constraints.

A.2.27 However, we note that some market participants have argued that there may be a specific issue with regard to plant which is both selected in the capacity mechanism to meet local capacity requirements and that are constrained-on in the Balancing Market to meet system constraints to a very material degree, or only runs when constrained-on. In considering such concerns the SEM Committee, along with the TSOs, will continue to consider the need for and an appropriate framework for any additional mechanism to address particular local security of supply concerns. These considerations will take account of the overall energy, capacity and system services market framework and relevant Grid Code requirements.

Statutory obligations to be able to finance activities

[53] Particularly if less reliant on renewables support mechanism, and more reliant on energy and capacity prices

A.2.28 The SEM Committee/ RAs do not have a statutory obligation to ensure that a market participant is able to recover all its costs, regardless of how over-supplied the market is.

A.2.29 As set out in the CRM Locational Issues consultation (SEM-16-052), the TSOs' 2016 Generation Capacity Statement indicates that there will be around 2,600MW of existing capacity in excess of the Capacity requirement, approximately a 35% excess. Given the subsequent decision not to include reserves in the Capacity Requirement, this excess is probably closer to 40%.

A.2.30 As we stated above, in a fully competitive market, with excess supply, absent the exercise of market power (both unilateral and co-ordinated) we would expect a bidder to include only its forward-looking costs in its bid. If it tried to include its sunk costs, it would substantially reduce its chances of winning in the auction, so we would expect it to include only those costs which are strictly necessary for its continuing operation in its bid.

A.2.31 In such circumstances, we would not expect all generators to be able to finance their activities, and we would expect some to exit. There is no obligation on the SEM Committee to ensure that all the excess generation can recover its total operating costs.

Not discouraging future investment

A.2.32 We do not agree that the SEM Committee's proposals will discourage future investment. New investment will be guaranteed a fixed capacity price for 10 years, and they are allowed to include their total costs in their bid. The length of the price fix is more than in any other capacity market around the world, other than GB, which is an outlier. It is more than the fixed price term of any US capacity market. After the first ten years, they are subject to capacity variation, but the presence of a capacity market will give them greater revenue certainty than in an energy only market, which many European markets are. As discussed above, once the current surplus of old inefficient capacity has exited, we expect new capacity to be setting the clearing price in most years, and this will dampen the volatility of the capacity price.

A.2.33 We recognise that the proposals set out in the CRM Parameters consultation did not explicitly provide for existing capacity to include recovery of an appropriate portion of unavoidable investment required to keep existing capacity operational. We recognise that in respect the proposals set out in the CRM Parameters paper differ from the treatment in US markets such as PJM. **We plan to adapt our approach to setting USPC to include an allowance for necessary investment**. This means that an existing plant will be able to recover capitalised costs without meeting the New Capacity Investment Rate Threshold (NCIRT). Most existing plant will not be required to make capitalised investment, so no additional provision will be included in the ECPC since the ECPC already includes an allowance for uncapitalised operating and maintenance costs.

Not discouraging efficient plant upgrades

A.2.34 As discussed above, we plan to adapt our approach to setting USPC to include an allowance for necessary investment. This means that an existing plant will be able to recover capitalised costs without meeting the New Capacity Investment Rate Threshold (NCIRT). Therefore:

- Efficient plant upgrades which exceed the NCIRT will be able to obtain up to a ten-year fixed price Reliability option at a price which reflects recovery of the new investment, just like an entirely new plant;
- Efficient plant upgrades which fall short of the NCIRT expenditure threshold will be able to recover their costs via including a proportion of their unavoidable investment costs in their bids each year of its remaining life, adopting a similar approach to PJM.

Consistency with State aid considerations

A.2.35 The SEM Committee is of the view that the proposed CRM is consistent with the State aid guidelines, and the proposed mechanism does deliver a solution which is secure, affordable and sustainable. It disagrees with the contention that the proposed arrangements are not sustainable because they do not allow existing generators to recover their total costs, and are not sustainable or secure as a result.

A.2.36 Bid caps which do not include sunk cost are central to simulating an outcome of competition in the current environment, and delivering an affordable outcome which reflects current market conditions in the first transitional auction.

A.2.37 The proposed regulatory regime only restricts recovery to current costs for generators who are marginal in both the energy market and the capacity market, and only when new capacity is not required. As explained above, once the current surplus of capacity is reduced by the exit of old inefficient capacity, new capacity may set the market price in a high proportion of years, and the capacity market may clear at close to an average of Net CONE, which is:

- Where we might expect it to clear at in a competitive market where no market participant is exercising market power; and
- Sends the right long term capacity price signals for investment.

A.2.38 It should also be noted that clause 231 of the EEAG states that, "The measure should be constructed so as to ensure that the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded". As we have pointed out above, at the moment the supply of capacity significantly exceeds the Capacity Requirement. Without the bid caps at the level proposed, it is likely that market power would sustain the capacity price at high levels.

A.2.39 We also do not agree that our proposals discriminate between new and existing generation in a way which is unjustified, and inconsistent with the State aid guidelines. We note that the GB capacity market, which received State Aid approval, has a different treatment of bid controls for existing and new generation in the same way as proposed for the I-SEM CRM, in that existing generators will be limited to bidding at 0.5 x Net CONE whereas new generators will be able to bid at 1.5 x Net CONE. The GB mechanism also has a different treatment of new and existing generation in terms of contract length, with the difference in contract length being more pronounced in GB (1-year vs 15 years) than the I-SEM (1-year vs 10 years).

Delivering required flexibility

A.2.40 It has been alleged that, greater flexibility is required and "by denying any prospect of total cost recovery, the I-SEM will destroy any incentive to invest in keeping capacity available, or in building new capacity – particularly within the constrained areas where capacity is most valuable to the system. Unless the SEM Committee gives immediate consideration to this problem, and provides relief from it by lifting or slackening some of the restrictions, the I-SEM will soon be in crisis with the prospect of further significant regulatory intervention being required to ensure security of supply".

A.2.41 Firstly, as discussed above, we do not agree that the proposed approach denies any prospect of total cost recovery. It does not guarantee cost recovery nor should it. Either with reference to economic principles, or to be compliant with State Aid.

A.2.42 As discussed above, we plan to adapt our approach to setting USPC to include an allowance for necessary investment. This means that an existing plant will be able to recover capitalised costs without meeting the New Capacity Investment Rate Threshold (NCIRT).

A.2.43 As explained above, international best practice does support our approach. Our approach is similar to that adopted in some US markets jurisdictions such as PJM (the largest and one of the best established capacity market in the world), which apply restrictions to bids in both the energy and capacity markets- and arguably more onerous restrictions.

A.2.44 We do not see the relevance of the distinction drawn between ex post scrutiny and ex ante scrutiny, to the nature of regulation. If bidders comply with the rules and/or ex post scrutiny is applied with appropriate diligence, it should result in exactly the same auction results as ex ante controls and incentives as ex ante scrutiny. The only relevant difference is administrative burden, ex ante scrutiny may result in scrutiny of bids that do not turn out to be relevant. The SEM Committee believes that the extra administrative overhead of ex ante scrutiny is appropriate and proportion given the level of market power, and the overriding consumer interest.

A.2.45 One respondent drew the analogy of ex post regulation applying in the SEM (as applied to daily energy market bids, where it is relevant). There is a significant difference between SEM energy market bids which are submitted on a daily basis and impact on prices for one day, and CRM auction bids which will generally[54] be submitted annually and may impact on prices for up to 10 years. Ex ante scrutiny is far more appropriate and proportionate for the latter.

[54] It is anticipated most generators will only participate in the T-4 auction for a given Capacity Year

Consultation summary

A.2.46 The methodology should seek to balance:

- Prudence that there is sufficient physical capacity available to back the Reliability Option, if for instance, demand outturn is higher than forecast. Prudence will support system security objectives, and serve to ensure that Suppliers are protected - there is less risk that a capacity provider could over-contract and face financial difficulties in meeting its difference payment obligations; and
- Enhancing liquidity and competition in the secondary market, and hence enhancing the ability of capacity providers to manage their Reliability Option outage risk and reduce their costs of capital.

A.2.47 The parameters consultation considered the granularity of the FPFCQSF, given the level of demand varies e.g. seasonally and by time of day, and the methodology and governance. In proposing a methodology it was considered whether to include a forecast element, how far in advance should the ex-ante load-following parameter be set and how this should all be governed.

A.2.48 The proposal was that the load following parameters be set ex ante for the whole Capacity Year, based upon historical ratios of demand in the relevant period to peak demand for that Capacity Year. A five-year historical averaging period would probably be sufficient, as any longer look back periods may capture times when the structure of economy and hence demand profiles were materially different, whereas as a five year look back period allows the parameters to adapt relatively quickly to economic development (e.g. the growth of data centres which could materially affect time of day/year demand patterns). However, we may want to incorporate a “safety” margin, rather than using the average headroom.

A.2.49 The granularity of these factors would be:

- Monthly. Load patterns vary significantly within quarters, e.g. October weather patterns are substantially different from December ones, so we consider that quarterly;
- Time of day: Broadly consistent with the trading periods in the energy market (Peak hours, Mid-merit 1 non-peak hours, other hours)[55] to allow for more consistent management of positions across Reliability Options and energy hedging instruments, and would be monthly granularity.

A.2.50 The resulting structure of the load following parameter would therefore be in line with that set out in Table 8.

Table 8: proposed granularity of ex-ante load following parameter

	Peak hours (currently 17:00 to 21:00) in winter	Mid-merit but non-peak hours (currently 07:00 to 17:00 and 21:00 to 23:00 on Business Days)	Other hours

[55] Peak hours and currently defined as Trading Periods arising during the hours beginning at 17:00 and ending at 21:00 on all days during, October, November, December, January, February and March. Mid-merit 1, i.e. Directed Contract mid-merit products, apply at the full rate for Trading Periods at the Contract Quantity during the hours beginning at 07:00 and ending at 23:00 on Business Days, and at 80% for days that are not Business Days. However, this application cannot logically apply to the load following factor, and we would propose to apply it only to Business Days.

January			
February			
March			
April	n.a.		
May	n.a.		
June	n.a.		
July	n.a.		
August	n.a.		
September	n.a.		
October			
November			
December			

A.2.51 We would propose that these parameters be estimated by the TSOs, for approval by the SEM Committee consistent with the outage planning process, since a key reason to allow secondary trading backed by the headroom between load following and peak demand is to support outage risk management. The current outage planning process is prescribed within OC2 of the Grid Code, and works on a Calendar Year basis, rather than a Capacity Year.

A.2.52 The TSOs provide generators with an approved outage plan for calendar year Y+1 by the end of September in the previous year[56], and it is reasonable to assume that prudent generators will want to manage their outages in the secondary market as soon as they know the approved outage plan. This would mean that the SEM Committee approved load following parameters for the complete calendar year Y+1 would ideally be published by the end of September.

A.2.53 There is a question of whether capacity provider should be able to use any headroom against load following for calendar year Y+2, and if so whether the load following parameters which apply for calendar year +1 should also apply to calendar year +2 (and possibly subsequent years too). Alternatively, it would be possible to “release” only a prudent percentage of the Y+1 load following margin for secondary trading in Y+2 and subsequent years, e.g. 75% in case the load following parameter matrix is subsequently adjusted the following year.

A.2.54 Respondents were asked for comments on the approach proposed for setting the load following parameter, specifically the granularity of the parameters, the proposed historically based methodology and proposed governance approach. Feedback was also sought on whether capacity providers should be able to trade against load following margin in calendar year +2 and any subsequent years, and should the parameters for subsequent years be scaled to 75% of the calendar year Y+1 values or some other percentage.

Consultation Responses

A.2.55 The majority of respondents agreed with adapting an approach similar to that outlined in the consultation paper. One respondent stated that they accepted the need for prudence to ensure there is sufficient capacity to support system security objectives and supports the benefit of enhancing liquidity and competition in the secondary market.

A.2.56 One respondent stated that higher levels of granularity should enable the volume of capacity available for secondary trading to be maximised, and stated that Monthly factors may be restrictive in winter months, or may be better to apply weekly granularity, or adopt a hybrid.

[56] Although the complete plan is not published on the SEMO website until the end of October

Another respondent stated that they would like to see products of the granularity of monthly, weekly, daily – weekday and weekend day and time of day.

A.2.57 One respondent supported calculations on a monthly basis. In relation to time of day periods, in principle it would be useful to align these with secondary products sold as much as possible for the sake of simplicity. Another respondent suggested that to improve liquidity Factors are determined ex-ante year ahead and open for consultation. It was suggested that Factors could be adjusted on a monthly basis to reflect changes to demand forecasts, and suggested that these factors should be shaped on a monthly basis and forecast elements should be built into the factor.

A.2.58 One respondent was concerned that the proposed approach would artificially constrain secondary trading in the Capacity Market, with the granularity of the Product Forecast Capacity Quantity Scaling Factor (FPFCQSF) linked to the granularity of the product being traded. This respondent suggested that it should not be rigidly defined to correspond to a particular period or time of the year as the granularity, timing and frequency of secondary trading products has yet to be defined. Another respondent suggested that there is no need for finer granularity definition of load following parameters.

A.2.59 One respondent stated that they viewed the granularity outlined in the consultation paper as a sensible approach to forecasting the load following profile, as it is reflective of the current financial forward products and load profiling and SEM. This respondent also suggested that the data should be updated in an annual review to reflect the outturn experienced in the new I-SEM markets.

A.2.60 One respondent who agreed with the approach outlined stated it should lend itself to more straightforward standardisation of instruments to trade forward power and secondary capacity. It was described how more complexity might free up additional de-rated capacity; this benefit should be balanced against the difficulty incorporating these into systems and products. One respondent noted there is no market maker obligation in secondary trading in wholesale market, with the possibility that non-portfolio generation could be left exposed.

A.2.61 One respondent stated that it would be advantageous if the parameters could be aligned with the CRM year, and recommended that at least the approach should be approved by the SEM Committee, since the parameters are of great importance to managing exposure in the CRM.

A.2.62 Another respondent stated that it is difficult to comment on this section without being provided information regarding the Secondary Capacity Products that will be allowed in the auction. This respondent stated that it seems prudent to maintain this level of granularity not to restrict the forms of secondary capacity product possible to allow for differential in trading of day/night maintenance schedules.

A.2.63 A number of respondents proposed a five-year historical averaging period of outturn data from SEM, suggesting it should be sufficient to determine the profile of available 'secondary' capacity, and be used as the best predictor of the forecast load following. Also, a number of respondents emphasized that whatever process is adopted it must be transparent as possible.

A.2.64 One respondent suggested that the whole exercise of setting these parameters, including granularity, historical methodology and governance is over-complicated and unnecessary, and stated that capacity providers should be allowed to make their own assessment of additional capacity that they can use to back secondary market sales of ROs and to be responsible for any risks they take on.

Load following in calendar year +2

A.2.65 The majority of respondents agreed with the approach of allowing participants to secondary trade their capacity positions more than one year in advance. Respondents acknowledged that a prudent approach is required, appreciating the issues associated with forecasting load following factors several years in advance, with a factor scaling the load following margin down. Another respondent acknowledged that a prudent approach is required until the demand forecast becomes more reliable closer to the delivery year. A number of respondents agreed with the figure of 75%.

A.2.66 A number of respondents agreed Capacity providers with the approach of allowing participants to secondary trade their capacity positions more than one year in advance but did not think scaling or amendments to the parameters should apply due to the uncertainty in the parameter matrix unless the RAs guarantee that these parameters will apply and in this case the full amount could be "released". Another respondent stated that given that load following parameters should be fairly consistent across years; they suggested that parameters should be applied to subsequent years without adjustment to allow generators to better plan outages.

A.2.67 One respondent stated that it is important to allow the values to be recalculated before each auction based on the most recent forecasts. In this way, the likelihood of allowing Capacity Market Units to trade above their de-rated capacity is minimised. One respondent stated that they are wary of formulating load following factors for secondary trades too far in advance, and suggested a prudent approach should be adapted for further out than one year.

A.2.68 A number of respondents did not agree with allowing secondary trading above the load following obligation further ahead than calendar year +1. Respondents cited the difficulty of predicting demand and weather patterns, particularly for over one year in advance, and will diminish the longer the forecast is made. It was argued that it still provides adequate liquidity to the secondary trading market. One respondent was concerned that the consultation seeks to be overly prescriptive on load following forecast to be used in the secondary traded market.

A.2.69 One respondent suggested that capacity providers should be able to make their own assessment of their ability to provide capacity in the secondary market and to take responsibility for any risks, therefore applying scaling factors to subsequent years is not necessary.

APPENDIX F UNIT SPECIFIC PRICE CAP BID TEMPLATE

Within the CRM design the majority of existing capacity providers will be subject to a non-technology specific Existing Capacity Price Cap (ECPC). However, some capacity providers may have higher unavoidable Net Going Forward Costs (NGFCs) than the Existing Capacity Price Cap allows. In such a case, an application can be made for a particular unit where it can be clearly demonstrated and evidenced that the unit's individual Net Going Forward Costs are higher than the ECPC.

To facilitate this application for a Unit Specific Price Cap (USPC) a template is currently being drafted which will set out the form and content required for such an application. A draft is provided in this CRM Parameters Decision Paper for information only, the final version will form part of the Initial Auction Information Pack. For those wishing to apply for the USPC, completion of the template and supporting documentation is to be provided to the RAs under the general electricity licence condition relating to the provision of information to the Commission (CER) and the Authority (UR).

The template has been designed around information currently provided to the RAs within the annual Generator Financial Reporting Templates. The template requires a combination of forecast revenue and costs together with historical revenue and costs. Further breakdown of both projected and historical Non-fuel Operating Costs are required. This information is then used to build the Unit Specific Price Cap (USPC) submission. The USPC submission will take into account Non Fuel Operating Costs (adjusted for variable cost elements), projected Infra-marginal rent and ancillary services, unavoidable future investment and de-rated capacity to arrive at a USPC submission determined in €(or £)/kW/year.

Applications will be assessed by the RAs on behalf of the SEM Committee following the deadline for USPC applications (same date as Qualification Application Deadline). Following review, the SEM Committee will determine if a USPC is appropriate and what value this should be. Notification of this will be provided when the Provisional Qualification Results are issued.

A draft of the USPC submission template is provided below.

I-SEM Capacity Remuneration Mechanism (CRM)
Unit Specific Price Cap (USPC) Application & Principles

Principles and Guidance for completing CRM Unit Specific Price Cap Application
Capacity Year: 1 October 2018 - 30 September 2019

Capacity Provider Name:	
Capacity Provider Unit Reference:	
Contact Name:	
Contact Direct Number:	
Contact Email Address:	
Confirm Financial Year End:	
Confirm Currency:	
Confirm Qualified De-rating Technology Class:	

This information is to be provided under the general electricity licence condition relating to the provision of information to the Commission (CER) or the Authority (UR).

The purpose of this template is to set out the principles and format for submitting a Unit Specific Price Cap application for the Capacity Year detailed above.

Applications must be made in this format, to ensure the submission is considered.

This information requirement includes a forecast for Net Going Forward Costs for the appropriate CRM capacity year together with a historical cost summary of SEM generator financial templates and a breakdown of non-fuel operating costs.

Applications should be made to both Regulatory Authorities, via email, to the following contacts:

Karen Shiels
The Utility Regulator
14 Queens Street
The Utility Regulator
BELFAST

Email: Karen.Shiels@uregni.gov.uk

Tom Quinn
Commission for Energy Regulation
The Exchange, Belgard Square North
Tallaght
DUBLIN 24

Email: tquinn@cer.ie

Application Submission Window: 3/7/2017 - 28/7/17 inclusive

Introduction
The information required will be used to inform Regulatory Authorities (CER and UR) when implementing and operating the I-SEM. The information will be used to aid understanding of the financial and economic performance of the business and to inform, inter alia, setting of a Unit Specific Price Cap (USPC) within the I-SEM CRM. It is also envisaged that additional information requirements may be necessary to ensure informed and appropriate decisions can be made.

Forecast Information
In relation to the capcity year being applied a best estimate forecast of Net Going Forward Costs should be provided. Please include within the notes the assumptions and further cost breakdown.

Based upon the SEM calculation for a Best New Entrant, we assume Net Going Forward Costs will broadly fall into the following categories:
Transmission, Market Operator and System Operator charges
Gas Transportation Charges
Fixed Operating and Maintenance costs*
Insurance
Business Rates
Cost of fuel working capital
Unavoidable Future Investment**

*Only fixed operating and maintenance costs should be reflected in the USPC application therefore an adjustment is necessary to exclude Variable Operation and Maintenance Costs. A consistent approach should be taken with the energy market bids under the Balancing Market Principles Code of Practice (BMPCOP).

Unavoidable Future Investment means costs which must be incurred if the **capacity is to be delivered.

Individual items greater that 2% of total Non Fuel Operating Costs, as per latest Generator Financial Template, should be detailed separately within the notes.

Where there are significant variances (i.e. greater than RPI inflation) arising between costs items within the USPC and the latest available historical information, a detail explanation should be provided.

The forecast information is requested for a 12 month capacity year.

Historic Information
Historic information will provide an understanding of the past financial performance of the business. Historic information will also assist in benchmarking costs as well as being used to identify Net Going Forward cost drivers.

Generator Financial Templates
A summary of Generation Financial Templates submitted should be provided and be consistent with submission previously made to the RAs. In the unlikely event the summary is inconsistent with the templates previously submitted a detailed explanation, including values, should be provided.

Data Entry
In accordance with normal accounting convention profits, revenues, assets and cash inflows are to entered as positive numbers with losses, expenses, liabilities and cash outflows recorded as negative numbers.

Forecast data should be provided in estimated 2018 prices for the year 2018.
Latest Forecast is a combination of actual data available and forecast data for the current year ie 2017.
All historical data should be entered in nominal terms.

All data fields highlighted in red must be completed. Additional notes can be provided in separate tabs to this worksheet.

Please include additional line items where you feel it may assist in understanding or accuracy.

Units
All figures are to be rounded to the nearest hundred thousand i.e. €/£245,000 becomes €/£245

Exceptional Items
Please detail each item you consider to be exceptional or atypical due to its size or effect.

RAs Confirmation regarding USPC application
The RAs will notify the application of the RAs decision as part of the provisional qualification results stage.
Where the RAs have determined a USPC bid for CY 2018/19 is appropriate and that bid includes a proportion of unavoidable future investment, evidence of the investment in line with the value and rationale in this application will be required before further apportionment can be applied to future Capacity Years ie 2019/20 onwards.

Capacity Remuneration Mechanism
Unit Specific Price Cap (USPC) Application
T-1 Auction for Capacity Year 2018/19

Capacity Provider Name:	
Capacity Provider Unit Reference:	
Contact Name:	
Contact Direct Number:	
Contact Email Address:	
Confirm Financial Year End:	
Confirm Currency:	
Confirm Qualified De-rating Technology Class:	

Generator Financial Template Summary	Forecast Revenue, Costs & MWh	Latest Forecast	Historical Revenue, Costs & MWh				
Financial Year (please specify year end month)	Month 2018	Month 2017	Month 2016	Month 2015	Month 2014	Month 2013	Month 2012
Volume of Electricity Sold - MWh							
Revenue	'000	'000	'000	'000	'000	'000	'000
Revenue from SEM Pool, made up of:							
Net Energy Payments							
Net Constraints Payments							
Revenue from Contract/Difference Payments							
Revenue from Capacity Payments							
Other Revenue, made up of:							
Revenue from Ancillary Services							
Revenue from Support Mechanisms							
Other Revenue Sources							
Total Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Operating Costs	'000	'000	'000	'000	'000	'000	'000
Fuel Related Operating Costs							
Non-fuel Operating Costs							
Total Operating Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EBITDI	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation							
Impairment							
EBIT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Interest							
Tax							
Net Profit	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Breakdown of Non Fuel Operating Costs (NFOCs) (based upon Generator Financial Templates)		Forecast NFOC Costs	Latest Forecast	Historic Non Fuel Operating Costs					Variance between latest financial template and 2018/19 USPC submission	
Financial Year		Month 2018	Month 2017	Month 2016	Month 2015	Month 2014	Month 2013	Month 2012		
Description	**Notes**	'000	'000	'000	'000	'000	'000	'000	2018/19 USPC est v 2016 actı	2018/19 USPC est v 2016 actual %
Transmission Charges	1								0.00	0%
Market Operator Charges	2								0.00	0%
System Operator Charges	3								0.00	0%
Gas Transportation Charges	4									
Operating and Maintenance Costs	5								0.00	0%
Insurance (please specify in note 6)	6								0.00	0%
Business Rates	7								0.00	0%
Cost of Fuel Working Capital	8								0.00	0%
Indexation to 2018*									0.00	0%
	10								0.00	0%
	11								0.00	0%
	12								0.00	0%
Total Non Fuel Operating Costs		0.00	0.00	0.00	0.00	0.00	0.00	0.00		

*Relates to Projected Costs 2018 column only.

Cross check

Total Non Fuel Operating Costs agrees with template value	Yes	Yes	Yes	Yes	Yes
Does historic cost information agree with generator financial templates previously received by RAs	Yes/No	Yes/No	Yes/No	Yes/No	Yes/No
If not, has a detailed variance report, including quantitative analysis, been provided?	Yes/No	Yes/No	Yes/No	Yes/No	Yes/No

Unit Specific Price Cap (USPC) Submission (Applying Forecast NGFCs above to a 12 month Capacity Year for USPC purposes)		Projected Costs CY 2018/19
Description	**Notes**	'000
Non-Fuel Operating Costs (NFOCs)		
Transmission Charges	As above	0.00
Market Operator Charges	As above	0.00
System Operator Charges	As above	0.00
Gas Transportation Charges	As above	0.00
Operating and Maintenance Costs	As above	0.00
Insurance	As above	0.00
Business Rates	As above	0.00
Fuel Working Capital (ongoing)	As above	0.00
Indexation to 2018*	As above	0.00
	As above	0.00
	As above	0.00
	As above	0.00
Adjustments re Variable Operating and Maintenance Cost elements of NFOCs		
Please describe	13	0.00
Please describe	14	0.00
Less:		
Unit Specific Projected Infra-marginal rent (corresponding note must specify assumptions including fuel price, carbon price and resulting electricity price assumptions)	15	0.00
Unit Specific Ancillary Services Revenue	16	0.00
Unavoidable Future Investment (if relevant) Please see note 17 in "USPC Submission Notes" tab for details required in submission	17	
Project Investment amount being recovered in Capacity Year 2018/19	18	0.00
Unit Specific Net Going Forward Costs (NGFCs)		**0.00**
De-Rated Capacity as per Qualification (kW)	19	0
Unit Specific Price Cap Submission (Price €(or £)/kW/year)		**#DIV/0!**

USPC Submission Authorisation

I agree that the above information presents a true representation of the historical, rolling estimate and projected costs and explanations and I understand this information will be used by the Regulatory Authorities in Ireland and Northern Ireland (CER and UR) for thepurposes of the SEM and I-SEM.

Director signature ______________________

Print Name ______________________

Date ______________________

Capacity Remuneration Mechanism
Unit Specific Price Cap (USPC) Application
T-1 Auction for Capacity Year 2018/19

Capacity Provider Unit Reference:	
Contact Name:	
Contact Direct Number:	
Contact Email Address:	
Confirm Financial Year End:	
Confirm Currency:	
Confirm Qualified De-rating Technology C	

Note 17: Unavoidable Future Investment

Please provide this note in a separate appendix (which may be in Microsoft word format) which succintly sets out the following:

1) Details relating to the current unit (before investment)

- Current CRM Qualified MW capacity
- Current running hour capability
- Year "commissioned" and unit age
- Useful life remaining
- residual unit value (please specify date value relates to)

2) Details of Proposed Unavoidable Future Investment, to include but not limited to:

- Total Unit Specific Investment value, including but not limited to the following:
    - Specify what is included in the investment including separate itemisation of costs over €/£1m
    - When expenditure will be incurred including annual profile
    - When investment is expected to be "commissioned" i.e. when benefits will commence.
    - Evidence of supplier quotes/tenders
- Reasons for Investment, including but not limited to the following:
    - Explain clearly why this investment is considered "unavoidable" ie must be incurred for **capacity** to be delivered.
    - Expected nameplate MW and De-rated MW investment relates to
    - Expected Nameplate MW capacity of unit after investment
    - Expected De-rated MW capacity of unit after investment
    - Expected running hours capability
    - Expected economic life of the investment
    - Expected residual unit value at end of Capacity Year 2018/19
    - Expected residual unit value at end of economic life of investment
    - Expected impact on Fixed Operating and Maintenance Costs, over the economic life, including value or percentage terms
- Outline full decision making process, steps taken to date and timeframe for remaining steps
    - Provide supporting evidence of decisions made e.g. Board minutes.
    - Commitments made at time of USPC application
- Outline full implementation process, steps taken to date and timeframe for remaining steps