Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism

Detailed Design

Decision Paper SEM-15-103

16 December 2015

EXECUTIVE SUMMARY

Ireland and Northern Ireland has until the end of 2017 to change its wholesale electricity markets to meet the requirements of the European 3rd package of energy legislation. This legislation places a number of requirements on the wholesale electricity markets of Member States with the aim of improving energy trade within the EU. The Regulatory Authorities (RAs) for Ireland and Northern Ireland have agreed the High Level Design[1] of the market required for the third package - and called that market the I-SEM (Integrated Single Electricity Market).

The proposed I-SEM closely models the "Target Model" that sits at the heart of the European 3rd package. Specifically, it includes the following energy markets:

- **Day Ahead:** The Day Ahead Market (DAM) will operate at 11:00 on the Day Ahead of the physical delivery of electricity. This will be a cleared market – where parties offer to buy and sell electrical energy for each hour of the following day, and all trades are priced at the price of the most expensive trade that is consistent with the received offers and bids.
- **Intra Day:** The Intra Day Market is bilaterally traded, and will operate from the closure of the DAM to a "Gate Closure", being some point close to the physical delivery of electrical energy.
- **Balancing:** The Balancing Market (BM) operates up to the physical delivery. This is the market where the Transmission System Operators (TSOs) adjust the output of generators (and demand of customers) as required to maintain the balance of generation and demand, and ensure the system operates in a stable and secure manner. These adjustments are made based on price data submitted by those Generators (or Demand Side Units (DSUs)). Any electrical energy that is produced or consumed, and which has not been explicitly sold or bought through one of these markets is deemed to have been bought or sold through the BM.

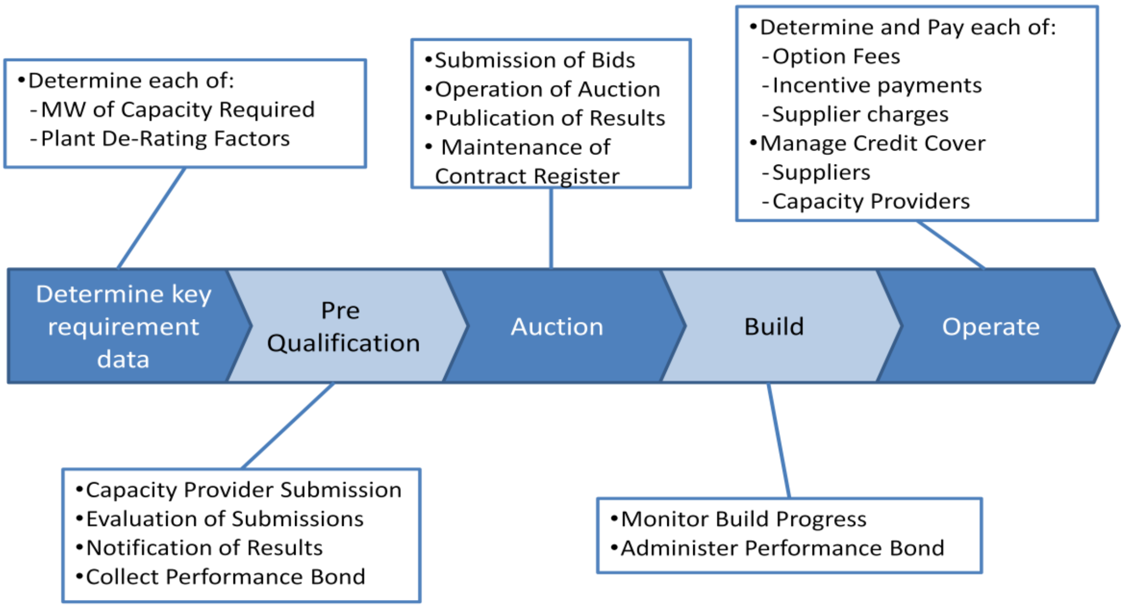
In addition to the above energy markets, the High Level Design includes a Capacity Remuneration Mechanism (CRM) based around Reliability Options. The CRM pays for the capacity to produce electrical energy on a "per MW" basis. This means that, typically, Capacity Providers can receive two payments

- A (per MW) capacity payment for being *available* to produce electrical energy; and
- An (per MWh) energy payment through one of the Day Ahead, Intraday or BM for any electrical energy they produce

The I-SEM CRM has 5 key stages as illustrated in Figure 1 below.

[1] http://www.semcommittee.eu/en/wholesale_overview.aspx?article=d3cf03a9-b4ab-44af-8cc0-ee1b4e251d0f

Figure 1: End to End Process for I-SEM CRM



In summary, these steps are as follows:

- **Determine key requirements:** This step involves fundamental analysis of the I-SEM requirements for capacity to determine:

  - The level of capacity that will be needed to maintain security of supply in future years; and
  - The extent to which each plant contributes to that need for capacity. This leads to factors that scale down the "name plate" capacity of each plant to give its "de-rated" capacity.

- **Qualification:** Qualification is the start of the procurement of capacity from providers. This process aims to identify those potential providers of capacity that are genuinely credible – and are likely to be able to deliver the capacity they offer. Those "credible" providers "qualify" to participate in the subsequent auction.
- **Auction:** The auction is a competition between *qualified* capacity providers to be awarded Reliability Options for the provision of capacity. This auction will allocate sufficient Reliability Options to at least meet the capacity requirement identified in the "Key Requirements" step. This allocation will aim to minimise the per-MW cost of those Reliability Options, based on prices submitted by each provider. The design of this auction will be considered in CRM Consultation 3.
- **Build:** Where the auction awards a Reliability Option to a new (as opposed to existing) capacity provider, that new capacity will need to be built. The arrangements for this "build" phase will include incentives on the relevant party to build their capacity within the required timescales.

- **Operate:** The "Operate" phase is when capacity is available to, and being paid by, the I-SEM. This leads to the following payments:

- "per MW" option-fee payments to capacity providers for their capacity
- "per MWh" difference payments from capacity providers at time when energy prices are high (above the Reliability Option Strike Price);
- Payments from Suppliers to cover the "per MW" option fee payments to capacity providers; and
- Payments to Suppliers at times when energy prices are high (above the Reliability Option Strike Price).

This paper sets out a number of decisions relating to the detailed design of that CRM. These decisions relate to issues raised in the first I-SEM CRM Consultation Paper – SEM 15-044[2].

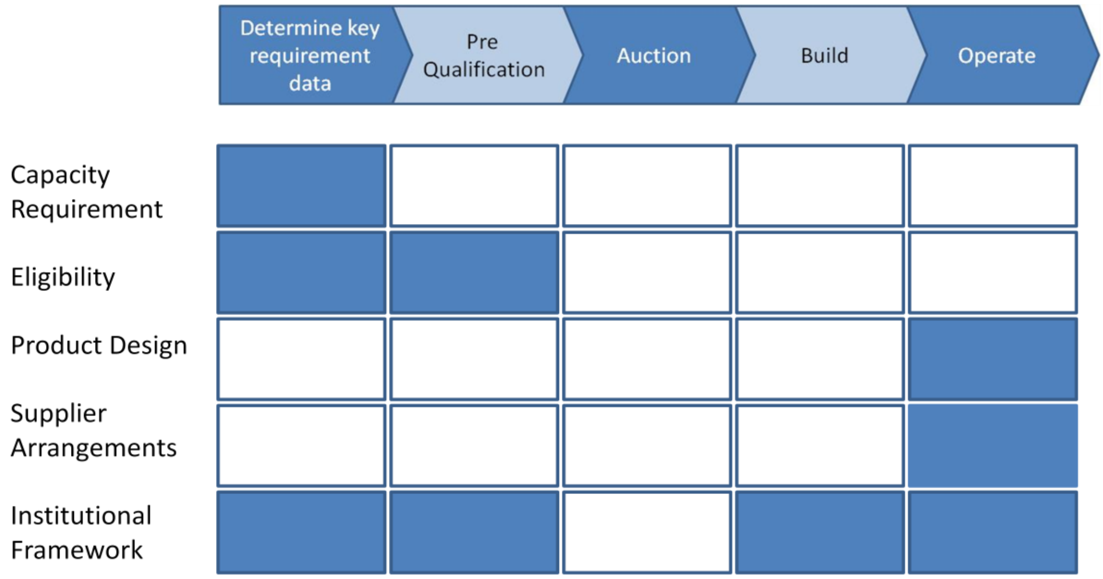
This Decision paper, and its associated Consultation paper (SEM 15-044), are the first of three consultations and decisions relating to the design of the I-SEM CRM. This consultation focuses on elements of the CRM design that are most likely to impact on the design of the central systems required for the CRM to operate. Subsequent consultations are envisaged as follows:

- The second CRM consultation will focus on a number of detailed design issues arising from Decision 1, as well as issues relating to international trade, transitional arrangements and secondary trading.
- The third CRM consultation will focus on auction arrangements for the allocation and pricing of Reliability options, as well as arrangements for the mitigation of market power.

The end to end process for the I-SEM CRM is illustrated in Figure 2 below, along with how that end to end process maps onto the key chapters of both the first I-SEM CRM Consultation Paper (SEM 15-044) as well as this Decision Paper.

[2] http://www.semcommittee.eu/en/wholesale_overview.aspx?article=4f400a98-6fc8-476e-892d-de81be0ca53a&mode=author

Figure 2: Key Decision 1 Chapters and the End to end process



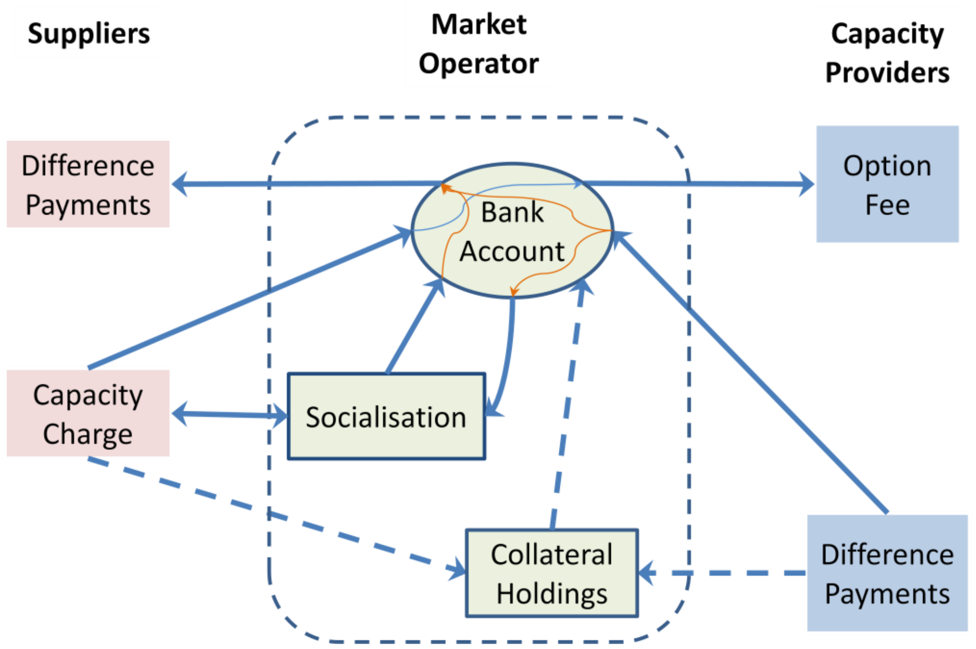
The following paragraphs provide a brief overview of each step in the end-to-end process, incorporating the decisions set out in this document. This brief overview:

- First covers the "Operate" step – as this includes the bulk of decisions contained in this paper;
- Then describes the remaining steps in the order shown in Figure 2; and
- Does not include any decisions relating to the middle "auction" step – as this will be covered in detail as part of the third I-SEM CRM consultation

Operate

The operate step is when the Reliability Option elements of the I-SEM CRM take effect giving rise to the cash flows illustrated in Figure 3. As set out in Section 5.3, parties that receive payments through these cash-flows will be insured against the credit risk that arise should any party fail to make the payments required of it. This is achieved by requiring both Suppliers and Capacity Providers to furnish collateral (credit cover) to a level that would cover their expected indebtedness.

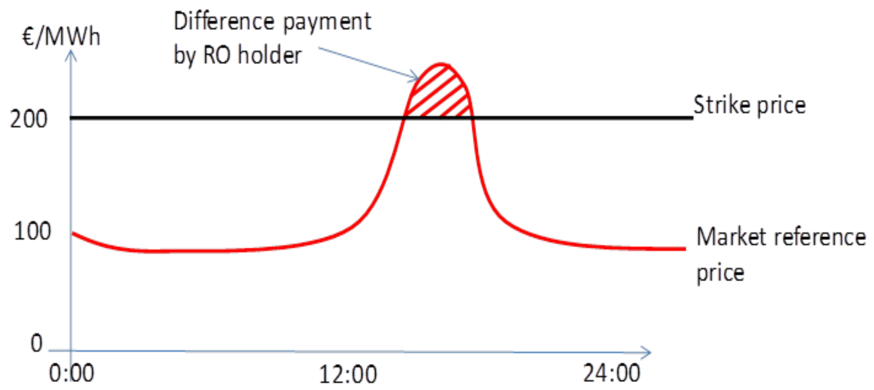
Figure 3: Reliability Option Cash flows



During this step, Capacity Providers that hold Reliability Options:

- Receive option fees at the €/MW year price arising from the relevant auction. Participants located in Northern Ireland will receive these option fees in Pounds Sterling, based on the exchange rate at the time of the auction that gave rise to the Reliability Option[3].
- Make difference payments when the price at which they sell power exceeds the Market Reference Price (MRP) specified in the Reliability Option (see Figure 4). For participants in Ireland, these payments will be made in Euro (€). For participants in Northern Ireland, these payments will be in Pounds Sterling (£) based on the relevant exchange rate at the relevant trading period.

Figure 4: Reliability Option Difference Payments



[3] See Section 5.4 for discussion on the treatment of exchange rates.

During the Operate step, Suppliers have a full hedge against I-SEM market prices that are above the Reliability Option Strike Price. If an I-SEM market price goes above the Strike Price Suppliers will pay that market price in the first instance, and then receive a difference payment to bring their net payments in line with the Reliability Option Strike Price. In return for these difference payments, Suppliers pay a Capacity Charge, the bulk of which is used to fund the Option Fees paid to Capacity Providers. As set out in Section 5.2, this capacity charge will be levied as a fixed price per MWh across consumption of electricity during a pre-defined set of hours.

These difference payments to Suppliers are primarily funded through the difference payments received from Capacity Providers as a result of that high market price. As discussed in Section 3.7, there may be occasions when there is a small shortfall in the difference payments received from Capacity Providers such that they are insufficient to cover the equivalent difference payments to Suppliers. In these cases, the shortfall will be socialised across all Suppliers through a combination of:

- Surplus difference payments – at times when difference payments received from Capacity Providers exceed those required to compensate Suppliers; and
- A small addition to the capacity charges recovered from Suppliers.

As set out in Section 6, the detailed arrangements for this Operate step will be captured in, and governed through, an updated Trading and Settlement Code. These arrangements incorporate a number of detailed decisions relating to the design of the Reliability Option (Section 37) and Supplier Charging (Section 5), notably:

- **Administrative Scarcity Price (ASP):** The BM will include an ASP, which will set a floor on the BM Price at times when available capacity is less than that required to cover electricity demand plus the associated reserve requirement. The inclusion of the ASP within the BM removes the need for any additional performance incentives within the I-SEM CRM.
- **Market Reference Price (MRP):** The MRP for the Reliability Options will reflect the price actually obtained by capacity providers in selling their power in I-SEM markets. This was presented as option 4b – the split market option in the consultation paper SEM 15-044.
- **Strike Price:** The Reliability Option Strike Price will be set dynamically to a level that should exceed the variable costs of most[4] of those offering energy into the I-SEM energy market.
- **Load Following:** The quantity that a Capacity Provider is contracted for under its Reliability Option will, for the purposes of difference payments, vary with the actual need for capacity – up to a cap of the level stated for that Reliability Option. This variation in contracted quantity allows the aggregate contracted capacity to reduce and track the quantity needed to cover demand and its

[4] It is possible that a limited number of Demand Side participants may have variable costs that are higher than the Strike Price; however, it intended to cover the per MWh fuel costs that could reasonably be expected of a thermal generator.

associated reserve requirements at any given time. This is achieved by reducing each capacity providers contracted quantity pro-rata to the extent required.

- **Charging Base including socialisation of uncovered difference payments:** Suppliers will pay a Capacity Charge to cover the cost of Option Fees, as well as to cover any estimated shortfall in difference payments receipts from capacity providers. Each Supplier's share of this charge will be determined based on their average market share over a pre-defined set of half-hours within a given year. This implements the "focused" approach as set out in SEM 15-044. As discussed in Section 5.2, this approach most accurately reflects the capacity costs imposed by different customers, leading to an equitable allocation of costs with the potential to improve overall efficiency.

In particular, there are three key elements of the overall CRM design which combine to deliver the key CRM objectives of ensuring all customers pay the same price for capacity. These three elements are the ASP, the MRP and the socialisation of any shortfall in difference payments.

The ASP provides sharp and cost reflective price signals at times of system stress. The ASP, combined with the chosen MRP option combine to give capacity providers a strong incentive to be available at times of system stress, and prevents unreliable generation from gaming the CRM, by being exposed to the ASP when not available. The ASP also provides Suppliers with a strong incentive to provide demand side response, reducing consumption at times of system stress, whilst at the same time, the choice of MRP option 4b, ensures that Suppliers who are unable to respond to these price signals have their price exposure capped at the RO Strike Price. As there may be occasions when the RO difference payments collected from capacity providers are less than the amount required to fully hedge Suppliers at the RO Strike Price, socialisation of supplier risk will be put in place to ensure that the hedge for Suppliers can be fully funded. The hedge for Suppliers may prove important in protecting Suppliers from scarcity prices, including ASP, and was one of the reasons underpinning the SEM Committee decisions to opt for centralised Reliability Options at the HLD stage. This hedge is expected to be more important for non-vertically integrated Suppliers (or vertically integrated companies that are net buyers of energy), who by definition do not benefit from the same natural hedge that fully vertically integrated utilities have, with higher generation revenue potentially offsetting higher Supply costs when prices rise to reflect scarcity.

These three key elements are discussed further in the following paragraphs

Administrative Scarcity Price

The SEM Committee has decided that the BM will include an ASP, which will set a floor on the BM Price at times when available capacity is less than that required to cover electricity demand plus the associated reserve requirement.

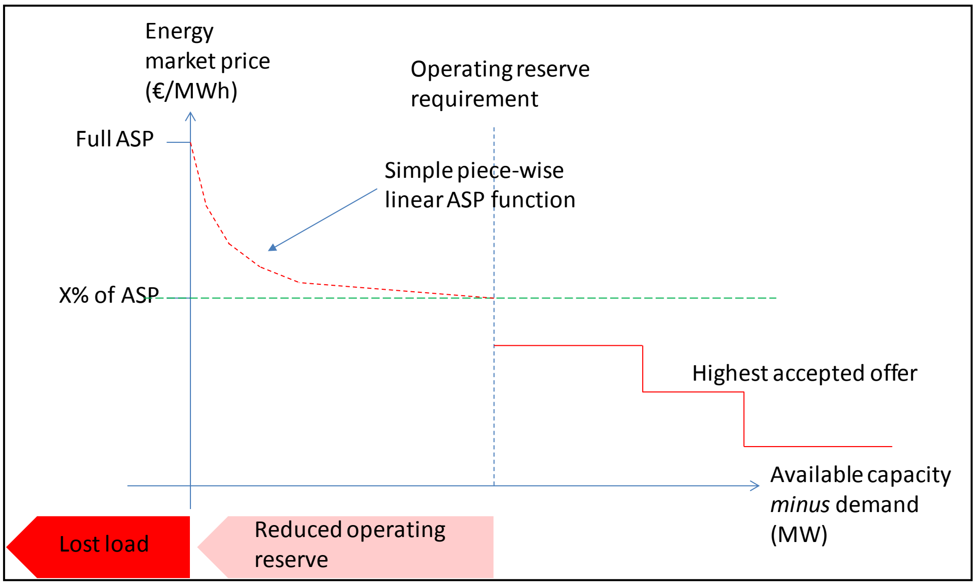
The SEM Committee is not convinced that prices will rise to reflect scarcity unless it is administratively introduced. This decision is based upon the experience of other markets where scarcity has not delivered high prices, and follows the model employed in a number of other markets, not least the interconnected GB market. However, if prices do rise to reflect scarcity, market determined outcomes will not be affected by the introduction of ASP, since the ASP is a floor price. The introduction ASP in the energy market promotes the following key I-SEM objectives:

- **System security**, by giving capacity providers strong marginal incentives to be available at times of system stress, and giving all Suppliers strong incentives to reduce load at times of system stress.
- **Efficiency**. By making sure that generators and Suppliers face the marginal cost of their actions (i.e. the value of lost load, if load shedding occurs), AS P also promotes economic efficiency.
- **Environment**. By strongly promoting demand response from all Suppliers, ASP would strongly support environmental objectives, through energy efficiency measures;
- **Internal Electricity Market**. The all-island electricity market is interconnected with the GB market, which has introduced ASP. Introducing ASP in the I-SEM will help facilitate consistency of price signals with the GB market at times of scarcity.

The ASP will apply as soon as available capacity is less than that required to cover electricity demand plus the associated reserve requirement. Triggering ASP before full load shedding occurs should give capacity providers and Suppliers earlier incentives to react to scarcity, reducing the likelihood of load shedding being required.

As illustrated in Figure 5 below, the ASP will increase in line with parameters set by the SEM Committee.

Figure 5: Parameterised ASP Function



As part of the second I-SEM CRM consultation paper, we will consult on the detailed definition of the ASP function. This will include:

- The level of the full ASP ;

- The percentage of ASP (X%) used as the start point for the function;
- Whether transitional arrangements are required such that the full ASP is relatively low at I-SEM go-live, and increases progressively over subsequent years.

Market Reference Price (MRP)

The MRP will reflect the price actually obtained by capacity providers in selling their power in I-SEM markets. This was presented as option 4b – the split market option in the consultation paper SEM 15-044. For a capacity provider this means difference payments under their Reliability Options will be determined as follows. :

- *Day Ahead:* For power sold in the I-SEM DAM (up to the quantity contracted through a Reliability Option), difference payments will be paid based on the difference between the Day Ahead Price and the Strike Price.
- *Intra Day:* For power sold in an I-SEM Intra Day Market (up to the remaining quantity contracted through a Reliability Option, in excess of that sold in the DAM), difference payments will be paid based on the difference between the traded price and the Strike Price.
- *Balancing:* For power sold through the BM (up to the remaining quantity contracted through a Reliability Option, in excess of that sold in the DAM and IDM), difference payments will be paid based on the difference between the relevant BM Price and the Strike Price.
- *System Services:* For any capacity utilised for DS3 System Services such as capacity providing reserve, difference payments will be paid based on the difference between the contracted utilisation payment for that service[5] and the Strike Price.
- *Delivery Shortfall:* For any capacity contracted through a Reliability Option that hasn't been utilised for DS3 System Services, or otherwise sold through an I-SEM market, difference payments will be paid based on the difference between the BM Price and the Strike Price.

The treatment of Suppliers is similar to that for Capacity Providers. They receive difference payments as follows:

- *Day Ahead:* For power purchased in the I-SEM DAM, difference payments will be based on the difference between the Day Ahead Price and the Strike Price.
- *Intra Day:* For power purchased through an I-SEM Intra Day Market, difference payments will be based on the difference between the traded price and the Strike Price.
- *Balancing:* For power purchased through the BM, difference payments will be based on the difference between the relevant BM Price and the Strike Price.

[5] Likely to be zero – implying no difference payments in respect of the provision of DS3 System Services.

This option was considered alongside a number of other options and was selected for the MRP for a number of reasons, including the view that, on balance, this option promotes the key I-SEM objectives better than the alternatives in two key respects:

- **Security of supply**: it better promotes the objective of security of supply by ensuring that only reliable capacity is rewarded, and unreliable capacity which fails to deliver at times of system stress will be penalised; and
- **Competition in Supply**: The Reliability Option, with the incorporation of this option, can serve to limit the exposure of Suppliers to high prices on unexpected volume changes. This supports the RAs' objectives of promoting competition in the retail supply sector.

Socialisation

The choice of Option 4b as the MRP for the RO mitigates the exposure of Suppliers to price spikes in the DAM, IDM and BM (including price spikes delivered through ASP). However, there are a number of circumstances in which the RO difference payments from capacity providers may not be sufficient to provide the full intended hedge for Suppliers. This has become known as "the hole in the hedge".

In adopting the I-SEM High Level Design, the SEM Committee saw significant advantages in the fact that ROs offer Suppliers a hedge against market prices spikes. Key advantages of ROs and particularly centralised ROs[6] included the facts that:

- Reliability Options provide Suppliers with a hedge against high prices. By doing so, the ROs better supports the SEM Committee's duty to promote effective competition;
- In providing all Suppliers with a hedge against high prices, ROs protect customers from price spikes – which is consistent with the SEM Committee's duty to protect the interests of consumers;
- Centralised Reliability Options ensure that all Suppliers, and hence by extension all end customers, face the same price for reliability in the I-SEM. As a result, Reliability Options promote I-SEM equality objectives.
- Socialising the impact of any short fall in difference payment will help maximise the benefits outlined above. The detail of the socialisation will be consulted on in CRM Consultation 3.

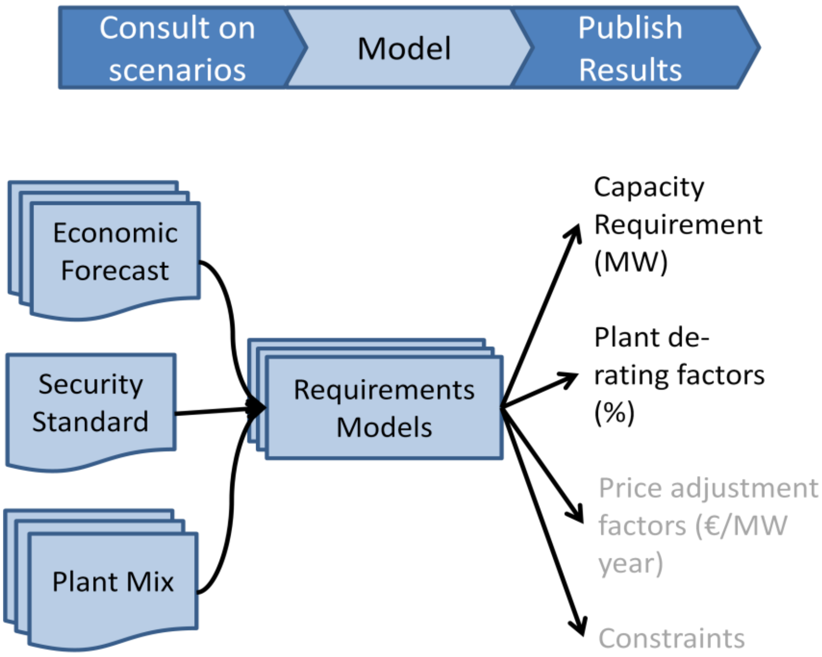
Determine key requirements data.

The "key requirements" step is the start of the end-to-end CRM process. This determines a number of factors relating to the need for capacity within the I-SEM, and the rate at which

[6] As opposed to de-centralised ROs where Suppliers contract individually at potentially different prices

different types of capacity contribute to that need. This overall process is illustrated in Figure 6 below – showing all the elements that were considered as part of the first CRM Consultation (SEM 15-044).

Figure 6: Elements of the "Key Requirements Data" step



As set out in Section 6, it is envisaged that additional licence conditions and codes will be developed to require the TSOs to run this process in a fair and objective manner. This will include (see Section 2):

- Developing scenarios covering the factors that drive the need for capacity (level of demand, wind patterns etc), with the aim that these scenarios cover a wide range of capacity requirements;
- Consulting on those scenarios leading to a SEM Committee decision on the final scenarios to use;
- Detailed modelling of the quantity of capacity required to meet the specified security standard in each scenario;
- Selection of the final scenario based on a "least regrets" approach. The selection of any scenario will lead to "regret" costs if that scenario does not accurately reflect the future. These regret costs are that consumers either pay for too much capacity, or for an increased level of un-served-load as a result of too little capacity. The scenario that has the least worst regret costs when compared to all other scenarios is selected.

The key outputs from the overall process are:

- **The Plant-De-Rating Factors:** These are scaling factors that are applied to the name-plate capacity of a capacity provider to give the quantity of capacity it is able to sell to back Reliability Options. As set out in Section 4.7 below, these will be "marginal" de-rating factors – reflecting how an increment of this type of capacity will impact the level of capacity required from other capacity providers. The TSO will determine de-rating factors for different technology types – and how this varies with key characteristics of that technology (e.g. size).

- **The Total Capacity Requirement:** This is the total level of de-rated capacity required to maintain the specified security standard.
- **Non-homogeneity factors: Section 2.5** shows two additional outputs - price adjustment factors and constraints. The SEM Consultation paper (SEM 15-044) considered whether the capacity requirement would need to differentiate between capacity providers for factors such as location. This could be done through adjustments to price, or by (a constraint) requiring a specific quantity of capacity be provided from a specific part of the Island. As set out in Section 2.5, the SEM Committee has decided that the I-SEM will remain a single zone for both energy and capacity – meaning these additional factors are not required at this stage.

Both of the total capacity requirement and the plant de-rating factors will depend on the security standard adopted for the I-SEM. SEM 15-044 consulted on changing this standard from its current level of 8 hours Loss of Load Expectation[7] (LOLE) to, for example, a 3 hour LOLE. As set out in Section 2.2, the SEM Committee has decided to retain the existing 8 hour LOLE standard, which is consistent with the current Value of Lost Load used for the island.

Qualification

Capacity providers will need to qualify for the auctions that will determine the price for, and allocate, Reliability Options. The details of this qualification step will be developed further both:

- To reflect responses to the related consultation SEM 15-091 relating to qualification for the provision of DS3 System Services; and
- As we further develop the overall procurement process as part of the 3rd I-SEM Capacity Consultation.

The future development to this step notwithstanding, this paper sets out a number of decisions relating to qualification. These decisions are set out in Section 4.9, and principally relate to the quantity of capacity that different types of provider are able, or obliged, to offer at this stage. The key such decisions are:

- **De-Rated Capacity:** Capacity providers (existing and proposed) will declare the quantity of de-rated capacity they propose to offer into the auction. This quantity must be within a specified tolerance of the de-rating factors determined in the “Determine Key Requirements” step. All plant will need to

[7] The Loss of Load Expectation can be thought of as the number of hours, on average, that at least some customers would have to reduce load because of capacity if the capacity on the I-SEM system exactly matched the capacity requirement.

provide evidence for why it believes its specific de-rating factor should be above or below the average for its technology type.

For dispatchable plant, the tolerance will be “tight” such that it does not either:

- Exceed a maximum tolerance specified by the SEM Committee (e.g. ±2%); and
- Exceed the range of de-ratings that is viewed as being reasonable for a given technology type[8]

For non-dispatchable intermittent renewable plant there will be a similarly tight tolerance on using a de-rating factor that is higher than the average for the plant type, however, these plant will be able to adopt de-rating factors down to zero – reflecting the potential risks for these plant.

- **Obligation to pre-qualify:** All existing capacity providers located within the I-SEM will be obliged to participate in the qualification process, and to declare the quantity of de-rated capacity they propose to offer into the auction. Where this capacity is zero, these providers will need to justify either on the basis that:

- They are an intermittent plant; or
- They are a dispatchable plant but will be genuinely unavailable for all, or a significant part, of the period to be contracted through the relevant auction. This would most clearly apply to plant that plans to close.

- **Supported Plant:** Some generation plant in the I-SEM receives financial support through other mechanisms. For example, renewable plant in Ireland is supported through REFIT, whilst those in Northern Ireland are supported through the UK Renewable Obligation. This plant will be eligible to compete for I-SEM Reliability Options on the same basis as plant of a similar type that does not have any support.
- **Demand Side:** Demand side participants will also be able to compete for I-SEM Reliability Options. At least initially, these participants may not be able to directly receive energy payments through the I-SEM. In recognition of this:

- Reliability Options issued to Demand Side Participants will only lead to difference payments where the relevant participant has failed to deliver its required response, and the market price has exceeded the Reliability Option reference price.
- The SEM Committee will continue to consider the introduction of energy payments for demand side participants as the I-SEM develops following go-live. Following any such revision, demand side participants would make difference payments in the same way as other providers.

- **Governance:**

[8] The practicality of using such tolerances will be kept under review as we develop the analytical approaches for deriving de-rating factors.

- The TSOs will administer the qualification process. New TSO licence conditions and codes will be developed to cover this administration role; and
- Obligations on capacity providers to participate in qualification will need to be captured. This will be achieved either through changes to the licences for those participants, or through changes to market (Trading and Settlement) codes.

Whilst most participants will qualify to compete for one year Reliability Options, plant requiring significant investment may qualify for longer term contracts. Whether this is the case, and the length of those contracts is one of the issues considered in the second I-SEM Capacity consultation.

Auction

It is envisaged that the TSO will operate an auction process to cover the procurement of sufficient capacity to meet the capacity requirement. It is currently planned that the design of the auction will be considered in the third I-SEM Capacity consultation. As such, the auction is not considered further in this paper.

Build

As set out in Section 6.5, new- build plant that are awarded Reliability Options will be required to provide a performance bond, and to enter into an agreement covering the build phase of that project This agreement will specify a number of project milestones relating the financing, build and commissioning of the plant. The size of the performance bond, and the specification of the milestones will be considered as part of the second I-SEM CRM Consultation.

Next Steps

A number of "next steps" have been identified associated with the decisions set out in this paper. These next steps fall into the following areas:

- **System Modelling:** There are a number of areas where more work is required to develop analytical methodologies that will impact the volume of Capacity that is procured through the Reliability Options. This relates to the approach to determine plant de-rating factors, and that to determine the overall capacity requirement. In each case:

- The TSOs will be asked to lead the development of these analytical methods;
- The RAs will separately consult on the methodologies, based on the work done by the TSOs.

- **Parameters:** A number of decisions in this paper are subject to specific parameters that will be set (and kept under review) by the SEM Committee. A number of these will be considered as part of CRM Consultation 2;

- **Detailed Settlement Rules:** Detailed rules for the Settlement of Reliability Options are under development, and will be considered in the implementation phase.

CONTENTS

1. INTRODUCTION

1.1 PURPOSE OF THIS PAPER

1.1.1 This paper details the SEM Committee's decisions on the first phase of the detailed design of the I-SEM Capacity Remuneration Mechanism (CRM). The paper also includes a summary of the responses made to the consultation paper issued on 2nd July 2015 and sets out the SEM Committee's response to the key points raised. Where relevant, next steps are also set out.

1.1.2 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 Department of Communications, Energy and Natural Resources (DCENR) and Department of Enterprise, Trade and Investment (DETI). The proposals in this paper have been developed to be consistent with guidelines published by the EC in this respect; however, the proposals are subject to the outcome of this notification process.

1.1.3 The structure of this paper is consistent with that of the consultation paper (SEM-15-044), with the key Sections summarised below:

- **Capacity Requirement**: Section 2 considers issues around setting the capacity requirement in the CRM, including consideration of the security standard; accounting for unreliability of capacity providers and uncertainty over future levels of demand; and consideration of locational issues.
- **Product Design**: Section 3 covers a number of aspects of the product design and includes consideration on if and how ASP should be introduced; what MRP should be used; how the Strike Price should be set and whether other additional physical performance incentives should be introduced.
- **Eligibility**: Section 4 considers which type of plant should be eligible to compete in the I-SEM CRM, and how different plant may need to be de-rated to appropriately reflect their contribution to meeting the capacity requirement. The treatment of demand side, energy storage and non-firm generation is also examined.
- **Supplier Arrangements**: Section 5 examines the basis upon which the cost and payments of the planned CRM are covered, along with the provision of credit cover and treatment of exchange rate risk
- **Institutional Arrangements**: Section 6 sets out the proposed governance arrangements for the CRM.

1.1.4 Each policy 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).

1.2 THE DETAILED DESIGN PHASE OF THE I-SEM CAPACITY MECHANISM

1.2.1 Over the course of 2014 the SEM Committee consulted extensively before publishing the decision paper on the High Level Design (HLD) for the I-SEM in keeping with our statutory objectives. The HLD decision sought to maximise benefits for consumers in the short-term and long-term, while ensuring security of supply and meeting environmental requirements. Following the HLD, the Detailed Design Phase of the I-SEM commenced and a number of workstreams were established including the CRM workstream.

1.2.2 The purpose of the CRM Detailed Design is to develop through consultation the specific design features of the new capacity mechanism that are consistent with the High Level Design of the I-SEM. Following on from this, detailed legal drafting of the CRM market rules will be completed. These detailed legal rules in the current SEM take the form of the Trading and Settlement Code.

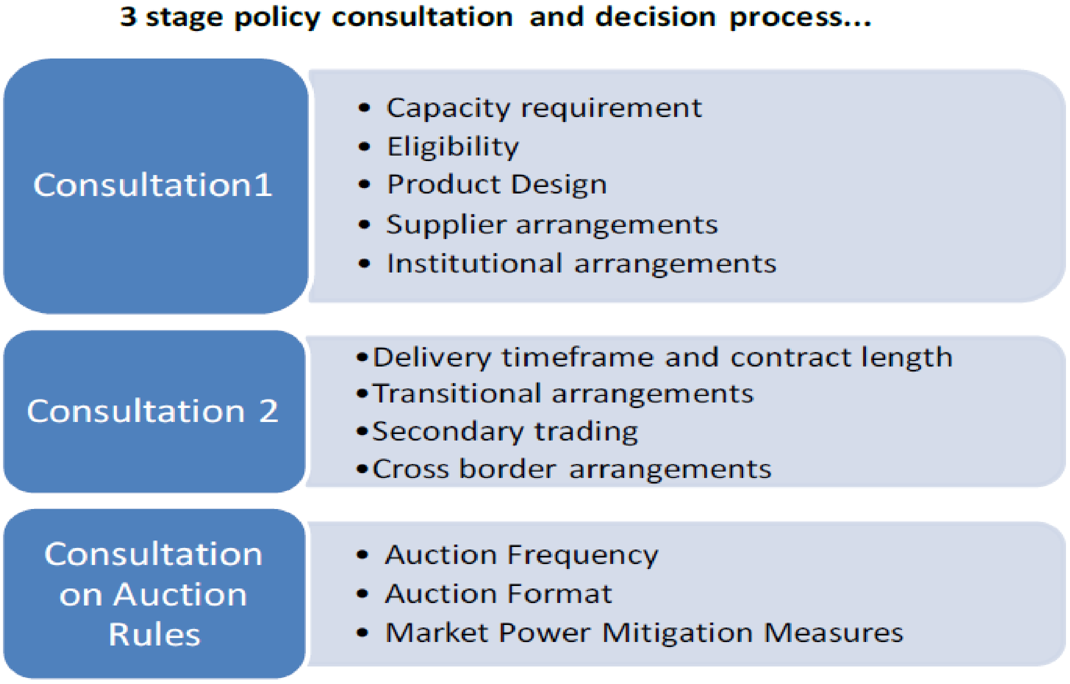
1.2.3 The SEM Committee and the Regulatory Authorities (RAs), in close cooperation with the Departments will continue to engage with the EC on the design of the I-SEM Capacity Mechanism, to ensure that the detailed design complies with existing and emerging European rules and guidelines.

1.2.4 In addition to the detailed policy design the RAs will be working with the TSOs in relation to systemisation and codification of the mechanism. It is important to ensure that there is alignment between CRM development, other I-SEM workstreams and DS3 System Services to ensure customers are protected and investors are appropriately incentivised.

1.3 CONSULTATION PROCESS

1.3.1 Development of the CRM policy will be carried out via a three stage consultation and decision process. This is the first decision paper of the three stage approach. An overview of the main topics (to be) discussed in each paper is given below.

Figure 7: Overview of CRM Policy Development



Consultation One: Key Milestones

1.3.2 A comprehensive programme of stakeholder engagement on the first consultation has been carried out over the past number of months by the project team. The following bullet points outline key milestones of engagement that have been carried out.

- Bilateral meetings with interested parties: 10 and 11 December 2014.
- First Stakeholder Workshop: 8 May 2015
- Consultation Document Published: 2 July 2015
- Second Stakeholder Worksop: 31 July 2015
- Third Stakeholder Workshop: 28 September 2015
- SEM Committee discussion: 29 October 2015
- SEM Committee decision: December 2015

1.3.3 Detail of and the slides presented at each of the workshops outlined above have been published on the All-Island Project website and in addition to these milestones, several further bilateral meeting have been facilitated at various stages of the decision development process.

Responses to Consultation

1.3.4 A total of 35 responses to the consultation were received. These were submitted from a wide range of interested parties including Generators, Suppliers, the System Operators, Network Owners and Industry Representative groups. Of the 35 responses, one has been marked confidential. The remaining 34 are outlined below and copies can be obtained from the All-Island Project webpage.

- IBEC
- SSE
- PPB
- ESB Networks
- Veolia
- ESB GWM
- Electric Ireland
- PrePayPower
- Moyle Interconnector
- Bord Na Mona
- Eirgrid/SONI
- NIRIG
- EAI
- Gas Networks
- Brookfield Renewable
- IWEA
- Schwungrad Energie
- BGE
- Power NI
- AES
- Energia
- EnerNOC
- DRAI
- Invis
- SIGA-Hydro
- Gaelectric
- Tynagh
- Aughinish
- IWFA
- Indaver
- ElectroRoute
- Mayopower
- Kore Energy
- Grange Backup

1.3.5 Some respondents provided comment on the consultation process employed to date and in general positive feedback was received. A point was made in relation to issue of a draft (or minded to) decision paper. The SEM Committee considers that it is appropriate to move directly to a Decision Paper on the first consultation paper of the CRM detailed design at this stage as the matters consulted upon have been widely discussed with participants in stakeholder workshops and bilaterally since December 2014. This has included providing industry the opportunity to question and provide feedback on emerging thinking for key decisions presented at a public workshop hosted on 28th September 2015.

1.3.6 Given that the implementation date for I-SEM has been set through EU legislation, the SEM Committee is of the view that the additional four to five months required for a draft decision on each CRM decision is not feasible and the time would be much better spent in the detailed rules drafting phase, as this phase will give interested parties more engagement on the detailed rules. There are many areas that still require refinement in the detailed rules and implementation phase.

1.3.7 Some respondents also raised the issue of carrying out a Cost Benefit Analysis (CBA) on the CRM design. The SEM Committee is of the view that a comprehensive CBA on the form of the CRM mechanism was already been carried out as part of the HLD. This concluded that a CRM based on centralised reliability options issued by a central party in the I-SEM represented the optimal solution. We do not believe that any evidence has been provided that would impact upon this analysis.

1.4 ASSESSMENT CRITERIA

1.4.1 Assessment criteria for the detailed design of the CRM, as set out in the consultation document, 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 March 2013. The 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.

1.4.2 In assessing the various options under the different Sections we acknowledge that there are trade-offs to be struck between the different assessment criteria.

2. CAPACITY REQUIREMENT

2.1 INTRODUCTION

2.1.1 Determining the appropriate level of capacity that is required to maintain the security standard is pivotal to the success or failure of any CRM. EU requirements for State Aid declare that this must be done in a manner consistent with ENTSO-E guidelines[9]. These are currently evolving, but through our engagement with the TSOs and our review of the ENTSO-E guidelines, the expectation is that:

- The quantity of capacity required will focus on a defined "generation" security standard; and
- The assessment methodology should consider a number of scenarios for the future level of demand, in line ENTSO-E guidelines.

2.1.2 In setting out the options for how the I-SEM requirement for capacity is determined, SEM Committee separately considered each of:

- The security standard to be used;
- How to derive a capacity requirement based on multiple scenarios for the future level of demand;
- How the capacity requirement accounts for the inherent un-reliability of different types of capacity; and
- Whether the capacity requirement should be adjusted to recognise locational requirements for capacity.

2.1.3 These are discussed further in the following paragraphs.

2.2 SECURITY STANDARD

Consultation Summary

2.2.1 As defined by ENTSO-E,[10] generation adequacy of a power system is "an assessment of the ability of the generation on the power system to match the consumption on the same power system". In practice, a defined level of adequacy (or security standard) requires that the level of installed generation capacity is higher than the level of

[9] Assessment of these guidelines is based on "ENTSO-E Target Methodology for Adequacy Assessment, 14 October 2014" and "Scenario Outlook and Adequacy Forecast Evolutions", ENTSO-E, 14 October 2014

[10] ENTSO-E Report, "System Adequacy Forecast 2010 - 2025", 2010

consumption at all times. This additional margin of spare generation capacity is required for when other generators are unavailable (e.g. due to a forced outage).

2.2.2 Across the EU there are currently numerous approaches to the assessment of the generation security standard – each of which leads to a different way of expressing that standard. The All-Island power system is currently managed against a generation security standard expressed as a Loss of Load Expectation (LOLE). This LOLE is a modelled estimate of the number of hours in an average year where there will be insufficient generation to cover demand. At present, the generation security standard is evaluated for the SEM as a whole, as well as separately for Ireland and Northern Ireland, using the following security standards:

- SEM: 8 hours LOLE
- Ireland: 8 hours LOLE
- Northern Ireland : 4.9 hours LOLE

2.2.3 As part of the consultation, SEM Committee:

- Set out a “minded to” position to retain the 8 hour SEM LOLE security standard; and
- Asked for views on this minded to position, compared with adopting a 3 hour LOLE security standard for consistency with neighbouring Member States.

Summary of Responses Received

2.2.4 A number of respondents favoured retaining the all-island security standard of 8 hours LOLE. Respondents stated that a move to a 3 hour standard would increase costs to consumers. Some respondents also argued that customers would not notice, or value, the move to a more reliable security standard.

2.2.5 A number of respondents favoured a 3 hour LOLE security standard. These respondents stated that a 3 hour standard would harmonise the I-SEM security standard with that in GB and France. They argued that increased plant margin arising from a 3 hour standard would be beneficial, given the increasing penetration of intermittent generation.

2.2.6 Some respondents argued that an improved security standard of 3 hours would support foreign direct investment in Ireland. A number of respondents described how the SEM has a track record of paying for an 8 hour LOLE standard but that the effective standard is closer to zero. One respondent described this as a good opportunity to introduce a security standard truly reflective of actual TSO practice and suitable to support the needs of an expanding digital economy.

2.2.7 A number of respondents stated a preference against retaining the 8 hour LOLE security standard but did not specify an alternative standard. One respondent described how it may lead to deterioration in reliability in the I-SEM. Another respondent described how we should have reliability and adequacy standards equivalent or better than competing economies. This respondent asked if the LOLE model is suitable, considering the island nature of I-SEM.

SEM Committee Response

2.2.8 The Security Standard represents a trade off between "equity" and "security of supply" assessment criteria. These factors balance two of the potential impacts of the Security Standard on consumers, notably:

- **Security of Supply:** A lower (e.g. 3 hour) LOLE would lead to an increased security of supply
- **Costs:** An increased security of supply implies customers paying an increased price for capacity.

2.2.9 To satisfy the "equity" assessment criteria, the trade off between these two factors has to be achieved in a fair way that reflects the actual value placed on electricity by consumers. This is achieved by setting the LOLE consistent with the Value of Lost Load for the System. That is, a Best New Entrant peaking plant would just cover its fixed costs if its annual running hours were the same as the LOLE.

2.2.10 In setting the LOLE consistent with the Value of Lost Load, the SEM Committee note that:

- The Value of Lost Load (VoLL) used in the SEM was determined for consistency with the 8 hour LOLE. Levels of VoLL for both Ireland and Northern Ireland were analysed in 2011[11]. This analysis indicates that whilst the level of VoLL for the SEM may be slightly higher than that currently used, it is not likely to be at a level required to justify a 3 hour LOLE.
- Recent analysis of the LOLE security standard for GB suggests that, in fact, much of the unserved load indicated by LOLE analysis would be managed without a significant impact on consumers[12].

2.2.11 Based on the standard above, the SEM Committee agrees with those respondents that noted moving the security to a 3 hour LOLE could increase costs to consumers without delivering an improvement they would value.

2.2.12 Some have claimed that the security standard will act to deter inward investment into Ireland. For this to be the case, those seeking to invest in Ireland would place a higher value on lost load than that currently used in the SEM. The SEM Committee is not aware of any evidence that a desire for inward investment would increase this VoLL, indeed it notes:

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[11] "An estimate of the value of lost load for Ireland", Energy Policy 39 (2011) 1514-1520.

[12] Paragraph 3 ii, Annex C to "Consultation of the Draft Electricity Market Reform Delivery Plan", GB Department of Energy and Climate Change, July 2013

- That many data centres and server farms have uninterruptible power supplies and backup generation, meaning a lower security standard could have limited impact on their location decision.
- As significant users of electricity, the price of that electricity has the potential to influence their location decisions.

2.2.13 Respondents' comments suggest that a number of other assessment criteria should impact the choice of a security standard. These factors are set out below and then discussed in the following paragraphs.

- **Internal electricity market:** A number of respondents noted that moving to a 3 hour LOLE would harmonise the Security Standard of the I-SEM with those of its neighbours
- **Environmental:** Some respondents claimed that a 3 hour security standard would support an increased penetration of renewable plant.

2.2.14 As noted by a number of respondents, the Security Standard may also impact the assessment criteria relating to the European **internal electricity market**. The SEM Committee notes that a 3 hour LOLE would be the same as that adopted in GB and France, giving an apparent benefit in harmonising the standards. However, we note that:

- **Energy Union:** Over the Summer, the European Commission has stated[13] that "Member States may have legitimate reason to establish different system adequacy standards to take account of national circumstances". The SEM Committee believe that the small size of the I-SEM system as well as its isolation from other AC power systems are such legitimate reasons.
- **Small System requires larger margin for the same standard:** The capacity margin required to meet a specified security standard is significantly larger for an I-SEM size system than it is for the GB or French systems, increasing the cost to consumers for an equivalent security standard.
- **8 hour is "Worst Case":** The 8 hour LOLE is the "worst case" security standard for planning and procuring capacity. Capacity tends to come in large lumps (e.g. 200MW) meaning that as capacity is added, the actual LOLE will be lower than 8 hours.
- **Small System means lower average LOLE:** The impact of adding new capacity on LOLE is greater for a small system such as the I-SEM than for a large system (such as GB). On average, this leads to a higher *actual* security standard for the I-SEM than would be observed for a larger system with the same *planned* security standard.

[13] Communication From the Commission to the European Parliament, the Council, the Economic and Social Committee and The Committee of the Regions: Launching the public consultation process on a new energy market design, July 2015

2.2.15 Some respondents claimed that an improved security standard would support the increased penetration of renewable generation. Were this the case, it would impact the **environmental** assessment criteria. The SEM Committee notes that the increased penetration of intermittent generation may increase the overall capacity required for the I-SEM. This increased need for capacity should be incorporated into the TSO's modelling of the capacity required to meet a specified security standard – with the total nameplate capacity increasing with the assumed penetration of such plant. As such, there is no need to increase the security standard to account for the increased penetration of intermittent generation

SEM Committee Decision

2.2.16 The SEM Committee has decided to retain the existing (8 hour LOLE) security standard. In making this decision, the SEM Committee notes:

- That any decision on the appropriate security standard of for the all-island system is independent of the I-SEM development.
- That this decision does not preclude the SEM Committee considering changes to the security standard at a later date – based on the information available at that time.

2.3 ACCOUNTING FOR PLANT UNRELIABILITY

Consultation Summary

2.3.1 All potential providers of capacity will have an element of un-reliability, meaning there are times they will be unable to perform, for example due to forced outages or intermittency. This unreliability is traditionally measured as the Forced Outage Rate (FOR) for a given plant or plant type. In its simplest form, the FOR is the percentage of time that the plant is unable to perform as planned.

2.3.2 Forced outages drive the need for a margin of spare capacity (over and above peak demand) to replace that which is unable to perform. The size of this margin will increase with the tightness of the security standard i.e. a 3 hour LOLE would require a greater margin than an 8 hour LOLE.

2.3.3 There are two options for how unreliability can be accommodated within the CRM:

- **Total Requirement:** This approach would determine the total "nameplate" capacity required to meet the specified security standard. This will result in a capacity requirement that may be higher than forecast demand, with the margin of additional capacity being required to cover the risks arising from the reliability of plant. This approach would be similar to that currently used by the TSOs to determine the capacity requirement for the SEM[14].

- **De-rated Requirement:** Under a de-rated approach, capacity providers will only be eligible for capacity contracts up to a defined fraction of their nameplate capacity. The defined fraction would vary by capacity type - reflecting its typical reliability, and hence its impact on the total nameplate requirement for capacity. This approach has been used in the GB market.

Summary of Responses Received

2.3.4 Respondents who commented on this area of accounting for unreliability of capacity mostly favoured the de-rating approach. One respondent described how it more accurately reflects how capacity will actually be provided and limits the potential for generators being paid for capacity that they will, in practice, be unable to provide.

2.3.5 One respondent stated that given the proportion of wind and DSR currently installed on the system, a de-rated capacity requirement is the best way to account for plant reliability. A number of respondents stated that the methodology used to de-rate participants should be appropriately dynamic, that it should take detailed consideration of the characteristics and performance of each technology in question and be updated regularly in line with developments in those technologies.

2.3.6 A number of respondents looked for full consultation and transparency over the methodology for de-rating.

SEM Committee Response

2.3.7 The SEM Committee agrees with the majority of responses received. The de-rated approach impacts positively the Security of Supply, Equity and Competition criteria and does not impact other criteria. Notably:

- The de-rated approach supports equitable and fair competition for Reliability Options between plant of different types; and
- As de-rating takes account of the rate at which different plant contribute to the security standard, it is more robust to changes in plant mix in ensuring the security standard (and hence Security of Supply) is satisfied.

SEM Committee Decision

2.3.8 The SEM Committee has decided that the procurement of Reliability Options under the I-SEM should be based on a de-rated requirement.

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[14] The methodology for the determination of the SEM Capacity Requirement is set out in SEM-07-13. http://www.allislandproject.org/en/capacity-payments-consultation.aspx?article=64eb1095-92de-4ae2-a053-19a3cfc2307b

Next steps

2.3.9 The TSOs have been asked to develop a methodology to determine this requirement, in consultation with the industry, for approval by the SEM Committee.

2.4 ACCOUNTING FOR DEMAND FORECAST UNCERTAINTY

Consultation Summary

2.4.1 EU / ENTSO-E requirements[15] imply a need to consider this uncertainty in demand forecasting. These guidelines imply that a number of scenarios should be used to inform future forecast levels of demand. Explicitly they note[16]:

- TSO's should follow specific guidelines to calculate the figures requested (e.g. GDP used in the demand forecast)
- The SO&AF[17] scenario building process and simulations should be transparent and publicly consulted on with stakeholders

2.4.2 There are a number of options for how the uncertainty around the demand forecast can be assessed for the I-SEM CRM, as set out below:

- **Single, average, scenario:** The requirement for multiple scenarios notwithstanding, this approach is likely to deliver a capacity requirement that will, on average, be less than that required to meet the defined (8 hour LOLE) security standard. This arises from the nature of the LOLE function - meaning that LOLE will rise faster as demand increases than it falls as demand decreases.
- **Worst case scenario:** It would be possible to determine the capacity requirement based on a "worst case" scenario, for example based on a 1 in 20 "bad" winter, leading to a high demand.
- **Select an optimal scenario:** This approach determines the capacity requirement under a number of scenarios, and then selects the "optimal" scenario based on a defined rule. This is the approach used by the GB capacity mechanism, where the rule to select the optimal scenario is based on that which minimises the "regret cost" as follows:

- If demand forecast is too high, the regret cost relates to buying too much capacity. This is estimated as the product of the estimated (per MW year) cost of capacity, and the capacity increment for that scenario relative to a base scenario (each of the other scenarios in turn).

[15] Assessment of these guidelines is based on "ENTSO-E Target Methodology for Adequacy Assessment, 14 October 2014" and "Scenario Outlook and Adequacy Forecast Evolutions", ENTSO-E, 14 October 2014

[16] Section 6, "ENTSO-E Target Methodology for Adequacy Assessment, 14 October 2014".

[17] Scenario Outlook and Adequacy Forecast

- If demand forecast is too low, the regret cost relates to a higher LOLE. The increase in LOLE is determined by evaluating the LOLE based on the assumed demand in a base scenario, with the level of installed capacity consistent with the scenario being evaluated. The "regret cost" is the product of the Value of Lost Load (VoLL) and the increase in LOLE.
- Each scenario's regret cost is determined with respect to each of the alternative scenarios.
- The scenario selected is that with the least worst regret costs.

  - **Stochastic modelling:** It is possible to envisage a stochastic approach that stochastically models the key factors that drive a need for capacity, and then more accurately determine the level of capacity required to meet a defined LOLE. This would probably go beyond any of the approaches currently used within Europe for the assessment of Capacity Adequacy. Whilst such approaches are not used at present, the I-SEM may need to adopt them if and when they emerge.

Summary of Responses Received

2.4.3 A number of respondents favoured the optimal scenario approach. Some of these respondents described how this is the most flexible approach that ensures demand forecasts are more likely to reflect the dynamic nature of the all-island market, and the most cost-effective procurement of capacity from the consumers' perspective. One respondent warned that whilst the optimal approach is theoretically elegant, it is inherently complex with a degree of latent subjectivity.

2.4.4 A number of respondents also favoured the worst case scenario approach. One respondent argued that the worst case scenario methodology is a prudent approach that should be taken given the small size of the all-island system and the blocky nature of power sector investment. Another respondent suggested that the worst case scenario should be chosen as the approach to mitigate demand forecast uncertainty, with it being prudent to take a conservative approach considering the scale of change proposed for the capacity mechanism. One respondent described how it should protect against the worst case scenario which would result in a considerable cost to the economy, and that this would also provide more confidence for foreign direct investment (FDI).

2.4.5 A number of respondents favoured the average scenario approach. One respondent described how the average scenario was the most straightforward approach, and it represents a reasonable estimation of the likely output of the stochastic modelling with much less complexity.

2.4.6 One respondent favoured the stochastic approach. One respondent described how it is important that stochastic modelling is implemented in calculating capacity requirements and could help with quantifying unreliability.

SEM Committee Response

2.4.7 There is clear uncertainty in forecasting demand a number of years forward. This is illustrated by the difficulties in forecasting future levels of GDP – one of the main drivers of future electricity demand. For example, June 2015 independent forecasts for 2016 UK GDP growth range from 1.2% to 3%, with each such forecaster believing their forecast is correct[18]. The level of capacity required is driven by other factors (such as the weather impact on demand, and the output from renewable plant), which is also subject to uncertainty. This strongly argues for the use of scenarios, and an informed choice between those scenarios.

2.4.8 The treatment of demand forecast uncertainty represents a trade off between the "equity" and "security of supply" assessment criteria. This is illustrated by considering the impact of selecting a demand scenario that is "higher" or "lower" than what actually happens:

- **Too high:** selecting a "high" demand scenario would lead to an increased security of supply. This would increase the costs of capacity, but reduce the expected level of unserved load.
- **Too low:** selecting a "low" demand scenario would reduce the security of supply. This would reduce the costs of capacity, but increase the expected level of unserved load (which is priced at VoLL)

2.4.9 To satisfy the "equity" assessment criteria, the trade off between selecting a scenario that is "too high" or "too low" has to be achieved in a fair way that reflects the actual value placed on electricity by consumers. This is achieved by:

- Having a range of scenarios for demand that cover a significant proportion of the potential future level of demand.
- Selecting the scenario based on an objective rule that attempts to trade off the costs of "too much" and "too little" capacity.

2.4.10 This is achieved through the "optimal" scenario approach. The SEM Committee note that the "worst case" scenario would provide an improved security of supply, but this approach takes no account of whether Consumers are prepared to pay for that improved security of supply.

2.4.11 The SEM Committee agrees that the "Single Average" scenario is simple but note that it is not entirely consistent with planning for an 8 hour LOLE. LOLP (and hence LOLE) is not a linear function, but increases close to exponentially as demand increases. This makes it more likely that the demand scenario consistent with an 8 hour LOLE is above the average scenario. The SEM Committee notes that the GB usage of the "Optimal" approach has led to the selection of scenarios that are above the "average" scenario.

[18] HM Treasury, "Forecasts for the UK Economy – a comparison of independent forecasts." June 2015

2.4.12 The SEM Committee agrees that a fully stochastic approach would allow a more accurate identification of the requirement for capacity, but note that this is beyond the current approaches used to determine generation adequacy.

SEM Committee Decision

2.4.13 The SEM Committee has decided that, in line with ENTSO-E guidelines, the I-SEM capacity requirement should be determined based on the analysis of a number of scenarios for demand. These scenarios should provide reasonable coverage of the potential future requirement for capacity. The capacity requirement should be determined for each scenario, and the optimal scenario selected based on the least regret cost approach as outlined in the consultation paper.

Next Steps

2.4.14 The TSOs should develop a range of future demand scenarios on an annual basis. For each such set of annual scenarios, the TSOs should run an open consultation process, publishing the scenarios and how they have been derived, in line with ENTSO-E guidelines.

2.4.15 The SEM Committee acknowledges and agrees with comments on the benefits of a more stochastic approach, especially relating to modelling the output from intermittent generation. Consistent with this:

- The methodology for determining the capacity requirement should be kept under review, and allowed to evolve with best practice and ENTSO-E guidelines;
- The TSOs are asked to consider whether the existing modelling of the output from intermittent generation can be improved – for example by considering multiple scenarios of their output.

2.5 LOCATION

Consultation Summary

2.5.1 In practice, the system is not indifferent to the location of capacity that is procured. The value of capacity may vary by location, reflecting transmission constraints (or the cost to resolve those constraints), as well as transmission losses.

2.5.2 The SEM is a single zone energy and capacity market and the working assumption is that the I-SEM will continue to be a single zone energy market (subject to the bidding zone review process under the Capacity Allocation and Congestion Management (CACM) Regulation). Locational signals for the provision of electricity in the current SEM include the use of Transmission Loss Adjustment Factors (TLAFs) and Generator

Transmission Use of System charges (GTUoS). These signals are considered outside the scope of this consultation.

2.5.3 The SEM Committee considered a number of options to deal with locational signals for capacity. These are summarised below:

- **Auction for a single zone:** This is consistent with the current arrangements whereby there is a single zone in both the capacity and energy markets. This option would be the simplest to implement, and will help mitigate issues in relation to market power and therefore facilitates a more competitive outcome.
- **Auctions for multiple zones:** This option splits the capacity market into two or more sub-markets (similar to the ISO NE capacity market and that in Italy), by introducing a locational constraint into the auction leading to zonal capacity prices. Whilst this approach has the ability to ensure an acceptable locational capacity mix, it would be more complicated to implement, particularly in the context of a single energy zone. The sub-markets will, by definition, be smaller than the entire market for capacity. This smaller market size will compound any issues of market power.
- **Locational Price Adjustment:** This option can be combined with auctions for either single or multiple zones. It adjusts the price of individual capacity bids to reflect the consequential costs (e.g. network reinforcement) of choosing one capacity provider over another. Capacity providers that are successful in the auction are then paid the auction clearing price less the adjustment to its bid. A method to deliver this price adjustment is likely to be complicated to deliver and challenging to implement for I-SEM go-live.

Summary of Responses Received

2.5.4 Most respondents supported having auctions for a single zone, albeit some of those respondents made their support conditional on the completion of the North-South interconnector. Respondents described how introducing further locational signals would introduce complexity, which would be challenging to achieve, and that avoidance of the complexity of multiple zone capacity auctions is preferable.

2.5.5 One respondent described how procuring the capacity on an all island basis is similar to how it is done currently and best mitigates market power, and described how the island is considered too small to break into more than one capacity zone without resulting in market power concerns.

2.5.6 Another respondent described how it is clear that there is a distinct long term need for capacity in Northern Ireland and therefore a locational signal is absolutely required within the competition, and supported a design which considers the need for capacity in both zones separately. This respondent stated that whether this capacity is realised in the same auction or a dual zone auction is a matter of detailed design.

2.5.7 One respondent supported having auctions for multiple zones. This respondent noted that zones may evolve over time and could, for example, emerge around specific cities.

SEM Committee Response

2.5.8 The SEM Committee agrees with the bulk of comments supporting a single zone. They note that the North South interconnector is expected to resolve any constraints before they impact the need for capacity. Were other significant and consistent constraints to emerge, they would be considered under the bidding zone review process under the Capacity Allocation and Congestion Management (CACM) Regulation.

SEM Committee Decision

2.5.9 The SEM Committee has decided that the I-SEM capacity requirement should be determined for the I-SEM as a whole, rather than for separate zones within the I-SEM. However the auction systems should be developed to handle multiple zones.

2.5.10 The SEM Committee is not intending to introduce locational pricing into the CRM, but may separately consider a review of GTUoS locational price signals.

2.6 SUMMARY OF SEM COMMITTEE DECISIONS

2.6.1 The following box provides a summary of the SEM Committee Decision relating to the Capacity Requirement.

- **Security Standard:** the existing 8 hour LOLE security standard will be retained
- **Accounting for Plant Unreliability:** the procurement of Reliability Options under the I-SEM will be based on a de-rated requirement
- **Accounting for Demand Forecasting Uncertainty:** the I-SEM capacity requirement will be based upon the analysis of a number of scenarios for demand. These scenarios will provide reasonable coverage of the potential future requirement for capacity. The capacity requirement should be determined for each scenario, and the optimal scenario selected based on a least regret cost approach as outlined in the consultation paper.
- **Location:** the I-SEM capacity requirement should be determined for the I-SEM as a whole, rather than for separate zones within the I-SEM. However auction systems will be developed to handle multiple zones, should this be required in the future.

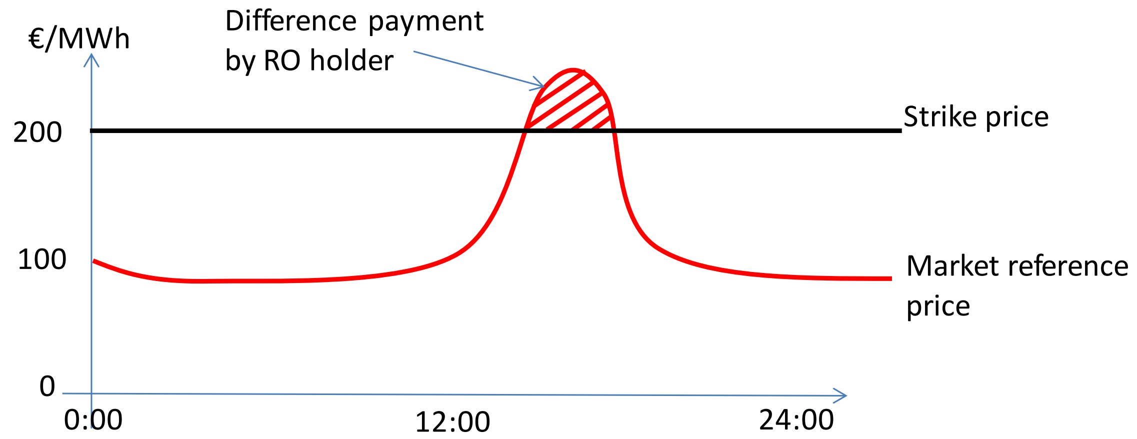
3. PRODUCT DESIGN

3.1 INTRODUCTION

The I-SEM High Level Design Decision Paper (SEM-14-085a) provided that the I-SEM Capacity Remuneration Mechanism (CRM) will take the form of centralised Reliability Options (ROs) with a requirement for backing by physical (e.g. generation) assets. The I-SEM Detailed Design CRM Consultation Paper (the Consultation Paper) further set out the key features of the RO product as follows:

- The RO takes the form of a one-way Contract for Difference (CfD), with a Strike Price (SP) and a MRP;
- The RO operates as follows:
    - The RO holder (i.e. the capacity provider) bids to receive a basic capacity payment. This capacity payment is analogous to an option fee, and will be determined by the result of a competitive auction;
    - In all settlement periods when the MRP exceeds the Strike Price, the RO holder will be required to pay an amount equal to the MRP minus the Strike Price to the RO Counterparties, the "difference" payment as illustrated in Figure 8. The Market Operator recovers / pays[19] the net difference between option fees paid out and difference payments received from Suppliers.

Figure 8: Difference payments under a Reliability Option (RO)



3.1.1 The Product Design Section of the Consultation Paper presented options on the following aspects of the detailed design of the Reliability Option product:

[19] In periods of high system stress, it is conceivable that difference payments could exceed option fees, so there may be a rebate to Suppliers, depending on the design of the product.

- **Administered Scarcity Pricing (ASP):** The paper considered whether ASP should be introduced into the I-SEM and whether this should be in the energy market (through the balancing mechanism and the pricing of energy imbalances) or as an additional performance incentive for capacity providers implemented in the CRM only. The paper also considered the definition of the trigger for ASP and the form of the ASP. The SEM Committee Decision is set out in Section 3.2.
- **Market Reference Price (MRP):** The paper presented a range of six options for the MRP, and we received an additional proposal from the TSOs as part of the consultation responses. The SEM Committee Decision is set out in Section 3.3.
- **Strike Price:** The Consultation Paper considered a number of key design issues relating to the Strike Price, including whether the Strike Price should be indexed or fixed, whether it should be based on an actual plant on the system or a hypothetical plant, and whether the Strike Price should be 'grandfathered'. The SEM Committee's proposed approach is set out in Section 3.4.
- **Load following:** The Consultation Paper considered whether the RO volume should be adjusted if scarcity occurred outside times of peak demand, i.e. whether it should be load following. The SEM Committee Decision is set out in Section 3.5.
- **Performance incentives:** The paper considered whether further performance incentives are required during times of system stress to complement the implicit incentives embedded in the standard RO. The SEM Committee Decision is set out in Section 3.6.

3.1.2 In addition to these issues during the course of the consultation and at public workshops on the consultation paper, the RAs held significant discussions with stakeholders about whether the difference payments received from capacity providers would be sufficient to cover difference payments due to Suppliers such that consumers would be fully hedged for reliability, or whether there would be a 'hole in the hedge', particularly if ASP were to be implemented in the I-SEM. The SEM Committee Decision, to socialise any Supplier difference payment shortfall and how such a mechanism would operate, is discussed in Section 973.7.

3.2 ADMINISTRATIVE SCARCITY PRICING (ASP)

Consultation Summary

3.2.1 The Consultation Paper discussed whether it would be appropriate to introduce ASP in the I-SEM (in the context of the CRM and the hedge provided by the RO). The Consultation Paper also raised a number of questions with regard to how ASP should be implemented, if it is implemented.

3.2.2 The first high level question raised was whether ASP should be implemented in the I-SEM energy market (in the BM), or whether **the** I-SEM energy market should rely purely on market determined outcomes for the BM. The Consultation paper also pointed out that alternatively it would be possible to implement a form of ASP through additional performance incentives in the CRM, without implementing ASP in the energy market. The ASP in the CRM could take the form of under and over-delivery payments at an ASP rate, and would apply to capacity providers only.

3.2.3 The Consultation paper noted that, if a decision was taken to implement ASP in either the energy market or the capacity market, a number of further decisions would need to be made. These decisions included:

- How should Administrative Scarcity be defined for the I-SEM? Options discussed included:

- Only when there is Lost Load; or.
- When there is reduced operating reserve due to insufficient available capacity.

- What level should ASP be set at, in the event of lost load or insufficient capacity to meet target operating reserve - if the trigger for administrative scarcity includes target operating reserve. The Consultation Paper set out approaches based on a Best New Entrant price and VoLL to apply when full load shedding applies, and argued that they typically generated the same values, as VoLL is often estimated by dividing the Best New Entrant cost by the number of hours of lost load. SEM 15-044 considered options for what ASP to apply if there was scarcity without load shedding, including highlighting the approach of using a Loss of Load Probability (LoLP) x Value of Lost Load (VoLL) function.

3.2.4 In addition, the Consultation Paper noted the GB approach of a phased increase in VoLL for ASP. During engagement following the issue of the Consultation Paper certain stakeholders requested that the ASP be set at a lower level for a transitional period, to reduce market participant risk at a time when a number of contemporaneous changes are being made to the energy, capacity and DS3 System Services.

Summary of Responses Received

3.2.5 The majority of responses received did not favour the introduction of ASP.

Responses against Administrative Scarcity Pricing (ASP)

3.2.6 A number of respondents who argued against ASP cited a range of reasons. These included:

- **A belief that unregulated energy prices should provide sufficient incentive without the need for ASP**. One respondent looked for evidence that prices will not be able to rise to VoLL and if such a market failure is likely to exist under the new arrangements. It stated that energy markets should be allowed to reflect market conditions free from bid and price caps, and if this was done then the need for ASP would be reduced. The respondent argued that evidence shown in the consultation document of unregulated price behaviour in GB was not directly relevant because of the PAR500 methodology on which the historical data was based. Another respondent argued that ASP assumed a market failure in the I-SEM before it is even designed. Another respondent described how it considered the emerging I-SEM design as providing sufficiently strong delivery incentives.

- **Volatility and risk**. ASP could increase the volatility of prices and the risk to suppliers from ASP if they are not fully hedged by the ROs.
- **Impact on auction bids.** Respondents argued that increased risk to capacity providers (and increased complexity) would be priced into auction bids;
- **Inability to respond to price signal**. Some respondents also expressed a view that Suppliers' would have limited ability to respond to scarcity price signals.

3.2.7 Another respondent opposed to ASP stated that issues in relation to interactions between the ETA, CRM and DS3 System Services work streams had not been addressed in the ETA or CRM consultations.

3.2.8 A number of respondents stated that they could not support the introduction of ASP without further information such as around how it is called, how its price is determined and which market it applies to.

Responses in favour of Administrative Scarcity Pricing (ASP)

3.2.9 Some respondents favoured the introduction of ASP. One such respondent cited how market pricing does not always respond adequately to system scarcity events and that based on this experience elsewhere that the introduction of ASP would be appropriate. This respondent described how it favoured an ASP related to the Value of Lost Load and which would also apply when further increases in demand would erode the reserve margin. One respondent supported scarcity pricing as a measure to incentivise market entry and reliable and responsible operations.

3.2.10 Respondents in favour of scarcity pricing required more information as to what would constitute a scarcity event and how such an event (and the pricing of same) would interact with the BM.

3.2.11 One respondent argued how scarcity pricing serves two purposes, in the short-term sending a signal for the market to balance itself, while in the medium to longer term, its purpose is to complement a capacity mechanism in facilitating market entry of new resources and on the corollary to signal the exit of resources.

Other Comments in Relation to Administrative Scarcity Pricing (ASP)

3.2.12 One respondent stated that scarcity pricing should be in the balancing arrangements and the triggers for scarcity pricing incorporated in the BM and imbalance pricing, rather than confined to the CRM. This respondent stated that scarcity pricing should not be considered in isolation to the CRM.

3.2.13 Two respondents that commented argued in favour of basing the definition on when the operating reserve margin began to be eroded, and not waiting until full load shedding occurred. Both respondents felt that this approach would better support system security and reduce the chances of load shedding.

Level of Administrative Scarcity Pricing (ASP)

3.2.14 One respondent replied that they would consider the scarcity price to be a regulatory-determined parameter, which it may be appropriate to set below the "true" VoLL as estimated for consumers. They noted that GB is introducing scarcity pricing with a VoLL of £3000/MWh in November 2015, rising to £6000/MWh in November 2018. Both these values are somewhat below the weighted average VoLL figure of £17,000/MWh as estimated for domestic and SME customers in a 2013 study commissioned by Ofgem and DECC. They noted that one of the arguments given for applying a lower VoLL for the purposes of scarcity pricing was that the introduction of a capacity market in GB reduced the need for the energy imbalance price to provide an investment signal at times of system stress. As noted in the consultation paper, for its part, DECC considered that the imbalance price limit of £6000/MWh was sufficiently high to incentivise performance when formulating the penalty regime for the capacity market

3.2.15 One respondent stated that the scarcity price could be set between the RO Strike Price and VoLL and could offer a signal to market participants to be available when they are needed most. This would mirror the implementation of scarcity pricing in GB and other markets internationally. This respondent described how options for formulating a scarcity price include a BNE cost or VoLL, and the balance of risks and incentives for capacity providers and other market participants could therefore be a consideration in setting an appropriate level for the scarcity price.

3.2.16 In addition, through further engagement during the consultation period one stakeholder argued that the Euphemia price cap of €3,000/MWh prevents the I-SEM DAM price rising higher than €3,000/MWh. They argued that if the ASP is set at a much higher level than €3,000/MWh, generators will be incentivised to withhold power from the DAM in order to sell it into the BM or the IDM, when there is a higher probability of scarcity.

SEM Committee Response

3.2.17 The SEM Committee thinks that it is appropriate for ASP to be considered in the context of the CRM and the protection to consumers afforded by centralised reliability options. The ability of the energy price to reflect scarcity requires consideration when designing incentives on capacity providers to be available at time of system stress, and in particular in incentivising demand response in the absence of a large, price sensitive, industrial load on the island of Ireland.

3.2.18 It is appropriate that Scarcity Pricing should be considered in conjunction with the design of the RO, since the RO is central to providing suppliers with a hedge to scarcity prices (whether administratively determined or market determined). Without an appropriately designed RO, which protects suppliers from very high and potentially volatile scarcity prices, ASP could have significant adverse consequences for competition in the retail markets in Ireland and Northern Ireland. The SEM Committee, in its I-SEM High Level Design Decision, stated that all consumers should pay the same price for the quasi-public good of reliability through the centralised RO auction and this equity principle was one of the key rationales for deciding on centralised ROs for the CRM design. Therefore, we consider that ASP without the complementary RO would place an unacceptable level of risk particularly on smaller suppliers and ultimately end-consumers. Notwithstanding the above the SEM Committee is cognisant of respondents concerns around the need to ensure that decisions on the CRM and ASP in the energy market are properly coordinated with other I-SEM workstreams most notably the Energy Trading Arrangements. In this context the detailed implementation of ASP will be included in the second CRM consultation and will be brought forward through implementation of the revised Trading and Settlement Code.

Overall case for administrative scarcity pricing in the energy market

3.2.19 The SEM Committee thinks that there is a strong case for scarcity based pricing in the I-SEM in order to promote the following key I-SEM objectives:

- **System security**:

- In the short term: by giving capacity providers strong marginal incentives to be available at times of system stress, and giving all Suppliers strong incentives to reduce load at times of system stress; and
- In the long term, by driving the right plant mix with the right entry and exit signals for flexible capacity

- **Efficiency**. By making sure that capacity providers and Suppliers face the marginal cost of their actions (i.e. the Value of Lost Load or a function of this, if scarcity occurs), ASP also promotes economic efficiency.
- **Environment**. By strongly promoting demand response from all Suppliers and incentivising investment in reliable, flexible generation that can respond to scarcity events, ASP would strongly promote renewable energy sources and hence environmental objectives;
- **Internal Electricity Market**. The all-island electricity market is interconnected with the GB market, which has introduced ASP, including Reserve Scarcity Pricing

prior to load shedding. Introducing ASP in the I-SEM will therefore help facilitate consistency of price signals with the GB market at times of scarcity.

3.2.20 The SEM Committee further thinks that it is appropriate to ensure that the energy market prices reflect scarcity by implementing ASP in the BM, and that the pricing of energy under scarcity conditions cannot be left entirely to the market. Experience from other markets around the world suggests that scarcity is not reflected in energy prices, even in energy only markets, and that without administrative intervention, the energy price does not rise to fully reflect scarcity. As a result, without administrative intervention, the energy price:

- Does not give generators fully cost reflective incentives to be available and generate at times scarcity;
- Does not give Suppliers and customers fully cost reflective incentives to provide demand response; and
- Does not necessarily reflect the cost of certain actions taken by the System Operator to manage scarcity, such as involuntary lost load-shedding.

3.2.21 As a result, the SEM Committee has decided to follow the lead of a number of other markets around the world and introduce ASP.

3.2.22 The SEM Committee is currently consulting on market power controls in the energy market in the I-SEM Market Power Mitigation paper, I-SEM 15-094. The paper discusses what market power controls should be applied to market participants' bids in the physical BM, IDM and DAM markets, and financial CfD markets.

3.2.23 The consultation paper, issued on 20th November, has requested consultation responses by 18th January and expects to issue a decision in Q2 2016.

3.2.24 SEM-15-094 discusses the forecast level of market power in the I-SEM and looks at how concentrated the ownership of capacity will be between 2016 and 2024. The paper concludes that capacity ownership will remain concentrated on most measures of market power (such as market share, Hirschmann Herfindahl Index and the Residual Supply Index) and that it is likely that certain market participants will be able to exert market power in I-SEM physical energy markets.

3.2.25 The paper indicates that the SEM Committee is likely to implement some form of explicit ex-ante market power mitigation measures in the BM[20], and is consulting on

[20] SEM-15-094 states..." "Even with REMIT (which is both ex-ante and ex-post in nature) and other ex-post measures available under I-SEM, the SEM Committee considers that relying on these measures would not be sufficient to protect customers and competitors from the exercise of market power, given the level of structural market power forecast for I-SEM. Hence the SEM Committee has concluded that some level of ex-ante mitigation measures (as well as ex-post) will be required to assist the competitive dynamic to a level that will lead to outcomes close or equal to SRMC....The SEM Committee further considers that mitigation measures that restrict the "ability" to exercise market power may also be required to ensure a competitive outcome in the various physical energy markets. The SEM Committee recognises that the competitive dynamic

the form of those ex ante market power mitigation measures. Whilst some generators without market power may not be subject to constraints, it is likely that at times of scarcity all generators will be deemed to have a degree of market power, and may be prevented from reflecting scarcity in their BM offers.

3.2.26 SEM 15-094 also indicates that the SEM Committee is likely to implement some form of controls on IDM and DAM price offers. The paper states that whilst the SEM Committee does not believe that it is appropriate to implement prescriptive bidding controls in the DAM and IDM, the SEM Committee is considering exerting controls via either a mixture of bidding principles and ex-post assessment, via ex-post assessment only or via a market abuse condition.

3.2.27 The rationale for ASP (as opposed to market determined scarcity pricing) interacts with the Market Power consultation, but the case for its introduction is strong:

- If the I-SEM does not have bidding controls, the case is that whilst theoretically, prices can rise to reflect scarcity, in practice they do not. ASP is a response to the risk of this market failure. ASP can be designed to provide a safety net where the market cannot or does not generate prices that reflect scarcity, and in such a way that the administered pricing does not interfere with the market where the market generates appropriate price signals.
- If the I-SEM has bid controls, then the case for ASP is that regulation intended to inhibit the exercise of market power at times when scarcity is not present (most of the time), also inhibits the emergence of scarcity based pricing on the few occasions when scarcity is present, and price signals are required to drive appropriate behaviour by capacity providers, suppliers and end customers to "keep the lights on";

3.2.28 We develop these arguments in more detail below under the following headings:

- Why scarcity should be reflected in energy pricing. This Sub-Section examines why:

- A well functioning CRM needs strong performance incentives; and
- Why these incentives should be in the energy market, not just the CRM;

- Why ASP is appropriate in energy markets generally, and the SEM Committee does not think it appropriate to leave scarcity pricing entirely to the market ; and
- Why ASP is necessary in a market with bid controls.

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differs across time periods and has proposed different mitigation measures accordingly. Based on the modelling in Section 6 which highlighted that generation plants may be especially pivotal in the Balancing Market (BM) due to its short-term nature, and due to local market power concerns in the BM (see section 4), the SEM Committee has concluded that a market power mitigation intervention is needed in this timeframe." .... "Given these concerns, the SEM Committee proposes implementing an explicit ex-ante bid mitigation measure for the BM."

3.2.29 We also consider the context of the I-SEM and its interconnection with the GB market, which has ASP.

Why scarcity should be reflected in energy pricing

3.2.30 The SEM Committee believes that it is important that the I-SEM energy price reflects scarcity, so that all market participants face the strong marginal incentive to generate, or to reduce load.

3.2.31 Some respondents have recognised that it is important to have strong marginal incentives on generators to be available and to generate at times of administrative scarcity, but have argued that these signals can be incorporated in the capacity mechanism through additional incentives and penalties on capacity providers, without the need for ASP in the energy market.

3.2.32 The SEM Committee does not agree with this view, because it places incentives purely on capacity providers, and does not place incentives on Suppliers (and indirectly their customers) who do not participate directly in the CRM. The SEM Committee sees value in placing appropriate incentives on all Suppliers to reduce load at times of system stress, and notes that the EEAG guidelines emphasise the importance of promoting demand response.

Importance of incentives on capacity providers

3.2.33 Strong incentives are essential to ensure that the capacity mechanism provides an incentive on generation capacity providers to increase the operational reliability of their plant and on demand response and storage to respond to the underlying economic signals in the market.

3.2.34 The academic literature on CRM design argues strongly for performance incentives above and beyond mere availability based payments or those embodied in the implicit incentive of a reliability option[21].

3.2.35 Furthermore, international experience with early designs of CRM's provides a substantial body of evidence that capacity markets with poor or minimal performance incentives risk selecting less reliable capacity providers.

3.2.36 If the RAs were to implement a CRM design that did not include strong performance incentives such as those provided by ASP, there would be a risk that providers who did

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[21] See: Batlle, Mastropietro and Rodilla, The Need for Non-Performance Penalties in Capacity Mechanisms: Conceptual Considerations and Empirical Evidence, April, 2015

http://www.iit.upcomillas.es/batlle/Publications/2015%20Capacity%20mechanisms%20and%20performance%20incentives%20_%20Mastropietro%20et%20al.pdf and

Cramton, Peter, Axel Ockenfels and Steven Stoft, "Capacity Market Fundamentals," *Economics of Energy & Environmental Policy*, 2:2, September 2013 not invest in improved reliability would be capable of bidding lower into the auction than those who would planned to make the required capital investments and priced in the costs of those investments into their bids. With strong performance incentives (such as scarcity pricing), the reverse is true and the capacity provider that intends making investments to improve operational reliability (or indeed new entrants investing in efficient, reliable plant) will be able to bid lower into the auction.

3.2.37 This was one of the fundamental arguments for the New England ISO introducing the scarcity pricing pay per performance regime into its forward capacity market, and its subsequent approval by the Federal Energy Regulatory Commission (FERC). Experience of Reliability Options in New England and the reliability capacity market in PJM has illustrated that during times of extreme weather and system stress (such as the polar vortex in the PJM region in 2014) the lack of strong performance incentives has revealed that the capacity mechanism design had failed to supply consumers with the required level of operational reliability.

3.2.38 This point is made clearly in the testimony of Matthew White, Chief Economist of the New England ISO to the FERC Hearing on the Pay Per Performance Regime:

> "More reliable, better performing resources can afford to submit low bids in the capacity auction because of the additional performance based revenue they obtain, making them more likely to clear in the capacity auction. Less reliable, poorly performing resources cannot afford to submit lower bids in the capacity auctions because the reduced capacity payments they receive will no longer cover their capacity costs"

and by Professor Peter Cramton as part of his testimony:

> 'Performance risk must be borne by consumers or suppliers [i.e. capacity providers]. It is performance risk that motivates good supplier [providers] decisions…having consumers bear that risk is wholly inappropriate, they can neither control that risk nor change suppliers behaviour to manage that risk'.

3.2.39 The European Commission Directorate General for Competition has also recognised the importance of strong performance incentives:

> 'If the need for penalties is based on a perceived problem of insufficient short term signals to ensure sufficient plant availability, or the penalty design is considered necessary to ensure the mechanism provides sufficient longer term incentives for investment in reliable and flexible capacity, then the penalties should in theory be linked to the value of lost load' (EC, CRM Workshop State Aid Guidance, 2015)

Why scarcity price signals should be in the energy market

3.2.40 A number of respondents have made representation for ASP to be reflected in the CRM only, and hence apply to capacity providers (generators and DSUs) only. However, **if scarcity pricing is confined to the CRM incentive regime only, Suppliers**

and their customers will not face the strong marginal incentive to reduce load at time of system stress (other than through participating directly in the CRM as DSR). If scarcity pricing is reflected in the energy price, Suppliers can benefit from reducing load and selling energy back to market at the scarcity price. Even if Suppliers' risk is capped by the RO Strike Price, Suppliers can still get the full marginal benefit of the scarcity price by selling back any load reduction relative to their DAM purchase volume via the IDM or BM, as prices rise to reflect scarcity.

3.2.41 Consider the case whereby a Supplier has bought 100MW in the DAM at €100/MWh at a point in time where scarcity is not expected. Now let us assume that scarcity occurs, and the market price rises to €10,000/MWh. Now let us assume that the RO Strike Price is €500/MWh. The RO may limit the incentive on Suppliers to buy more power - e.g. if its customer demand increases to 101MW, then it will only pay €500/MWh for the incremental MW. However, if the Supplier can persuade its customers to reduce demand below 100MW, then it can sell the incremental MW back into the BM or intra-day market at €10,000MWh - a strong demand response incentive in the energy market.

3.2.42 This provides Suppliers with stronger incentives than currently exist to negotiate demand response arrangements with a wider range of customers with half-hourly metering. This incentive is important in the light of:

- The limited amount of price sensitive industrial load on the island of Ireland. In markets such as Texas, where there is a significant amount of price sensitive industrial load, prices do not need to rise too high to elicit a strong demand response. However, on the island of Ireland, experience suggests that stronger incentives are necessary to elicit increased demand response;
- The environmental objectives of the Governments of Ireland and the UK, and the EC, and the desire of all three bodies to promote demand response. If more demand response is brought forward in the medium to long term as a result, this may ultimately lead to the removal of the need for a CRM.

3.2.43 Whilst some stakeholders have argued that there are limits on the ability of Suppliers or customers (other than CRM Demand Side participants) to respond to price signals that may only manifest themselves close to real time, to the extent that scarcity is reflected in intra-day or day-ahead markets, there is scope for customers to react. Moreover, we expect the ability of customers/Suppliers to react to increase with the adoption of new technology, such as increased smart metering.

3.2.44 Introducing a capacity mechanism alongside an energy market that does not properly reflect scarcity conditions in its prices risks creating what has been described as the 'missing incentive' problem. International best practice point to a need for additional performance incentives to be implemented as part of capacity mechanisms to incentivise operational reliability and ensure consumers receive the full benefit of the product that they are paying for. While other performance incentives exist, the most efficient, transparent means of ensuring the incentive has its desired effect is through the pricing mechanism.

3.2.45 The SEM Committee further notes that the EU “summer package”[22], states that it is an “essential condition for electricity markets sending the right price signals for investment in adequate capacity is to allow prices to reflect scarcity during demand peaks, and for investors to have confidence in this translating into long-term price signals.” Whilst the “summer package” paper does not explicitly mention ASP, it provides an indication that the EC direction of travel is to ensure that energy market prices reflect scarcity.

Why administrative intervention is appropriate in scarcity pricing

3.2.46 In a competitive market, prices should reflect marginal costs under normal conditions. It is during scarcity periods, when the market is ‘tight’ and demand has reached the market’s short run supply limit that prices should rise to the level that consumers place on the last unit of electricity produced.

3.2.47 This tends to be a particular feature of markets where the good cannot be easily stored (e.g. hotel rooms, electricity or airline seats). Given this, producers in many markets are required to cover their fixed costs and earn the return on their investments through what they deliver to the system during scarcity events. This, in turn, incentivises producers to ensure that they are capable of delivering during scarcity events and to make the required investments.

3.2.48 A number of respondents suggested that the removal of the requirement for generation to offer at short run marginal cost into the energy spot market might naturally lead to market determined energy prices that reflect scarcity

3.2.49 However, the SEM Committee is of the view that energy prices in the I-SEM may not appropriately reflect scarcity unless ASP is implemented. This is not necessarily just a feature of the market on the island of Ireland but rather is part of a wider set of international evidence that energy market prices do not rise to reflect the true economic value of scarcity during times of system stress. Evidence from both European markets and those in the United States points to this market failure, otherwise known as the ‘missing money problem’. Whilst there are relative few instances of blackouts or near misses in European markets, which could prove that market prices fail to react naturally to scarcity, in SEM-15-044, we presented some **evidence from other wholesale electricity markets to suggest that scarcity may not be reflected in prices unless ASP is introduced**. Key evidence includes experience of recent scarcity events in France and GB.

[22] Launching the public consultation process on a new energy market design, EC published 15 July 2015

3.2.50 The western European system suffered a significant disruption on 4th November 2006[23], which resulted in France having a blackout. However, imbalance prices did not rise to anywhere near VoLL levels. They remained below €100/MWh[24].

3.2.51 There are two relatively recent events in GB in which National Grid published a Notice of Insufficient Margin (NISM).

3.2.52 National Grid issued a NISM on 11 February 2012. However, the highest System Buy Price (SBP, the price paid for accepted generator offers, excluding for transmission reasons) during that NISM was only £264/MWh, a price that did not reflect scarcity. In their responses, some commentators correctly pointed out that the GB evidence was based on a historical period when the imbalance price was calculated over 500MW of balancing actions (PAR500), which blunted the imbalance price. They noted that Ofgem have now implemented reforms to the cash out mechanism so that the imbalance price will be based on more marginal actions (PAR50 from 5 November 2015, and PAR1 from November 2018), and hypothesised that it was the excessive averaging in the imbalance price rather than using a better approximation to a market clearing price that prevented the imbalance price from reflecting scarcity. However, Ofgem has published calculations of what the imbalance market prices would have been if the new calculation methodology had been applied during the period March 2010 to October 2015, if the PAR1 and single cashout price reforms had been in place during that period. This analysis indicates that, even if PAR1 had been in place in February 2012, the imbalance price would have only risen to £288/MWh.

3.2.53 We note that Ofgem extensively reviewed the GB imbalance arrangements under the Electricity Balancing Significant Code Review, and concluded that it is prudent to introduce ASP in the GB market, which does not have bid caps or price caps, and has a capacity market. They concluded that a change of the PAR averaging approach, was not, on its own, sufficient.

3.2.54 Ofgem's rationale for including Administrative Scarcity Pricing, as well moving to a better approximation to a market clearing price[25], is that without Administrative Scarcity Pricing the imbalance price does not reflect a range of uncosted actions taken by the System Operator, namely:

- Costs incurred in using Short Term Operating Reserve contracts for energy balancing. These have been reflected in the imbalance price by implementing a

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[23] See for instance http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2007/E06-BAG-01-06_Blackout-FinalReport_2007-02-06.pdf

[24] See http://clients.rte-france.com/lang/an/visiteurs/vie/mecanisme/histo/prix.jsp?&selchoixan=2006&selchoixmois=11&selchoixjour=04

[25] Which includes a single imbalance price instead of dual System Buy Price and System Sell Price, as well as PAR1- averaging only over the marginal 1MW of energy balancing actions

Reserve Scarcity Pricing which is a function of VoLL and the Loss of Load Probability, if the System Operator has to call on its Short Term Operating Reserve contracts[26]; and

- The cost of Demand Control[27] actions such as involuntary load shedding-i.e. the Value of Lost Load.

3.2.55 There was also a very recent NISM published on 4 November 2015, i.e. after the SEM-15-044 consultation period closed, and coincidentally the day before a package of changes were introduced into the imbalance price calculation approach. On 4th November, the imbalance prices rose slightly higher, to a maximum of £419/MWh in one half hour, but still only averaged £164/MWh during the period of the NISM.

3.2.56 A number of other markets have introduced ASP in some form. Examples include:

- Belgium: there is provision for the imbalance price to rise to €4,500/MWh, if in real time, the System operator has to call on the Strategic Reserve for two consecutive 15 minute settlement periods.
- ISO markets in the United States. Many US markets have Administered Scarcity Prices - see Table 1.

3.2.57 It is important to stress that the ASP merely sets a floor to the energy market price - they are not adder to the energy market price, and will not interfere with market determined prices, if prices rise to reflect scarcity. If market bids and offers are higher and reflect scarcity anyway, the market determined prices will prevail. The ASP will only take effect if the market has failed to deliver prices that reflect scarcity.

3.2.58 The SEM Committee recognises that the corollary to strengthening incentives is that ASP increases risk on capacity providers and Suppliers. ASP also increases the risk on generators in that they have to buy back power at the ASP, if they have forward sold their power prior to scarcity and then have to buy back a forced outage under conditions of scarcity. However, the price will merely reflect system conditions, and provide appropriate incentives on generators to be reliable. As discussed in Section 3.7, Supplier's risk will be mitigated through the design of the Reliability Option and through the socialisation of any shortfall in difference payments.

Why ASP is necessary in market with bid controls

3.2.59 It is important to differentiate between high prices that are due to the exercise of market power and high prices arising due to scarcity which are necessary to signal the need to make additional generation available (including new investment) or to curtail demand.

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[26] See B&SC Modification P305

[27] A Demand Control Event is one of three events defined in OC6 of the GB Grid Code: demand disconnection, voltage reduction or Low Frequency Demand Disconnection

3.2.60 As discussed above, it may be necessary to implement ex ante bidding controls on BM offers and some form of controls on generators' offers in the DAM and IDM. Such market power controls could serve to restrain prices, and are likely to prevent prices reflecting scarcity. Therefore in a market with regulated offers, the case for ASP is very clear.

3.2.61 Most US markets, which have a higher degree of explicit, and often ex ante regulation of generator offer prices, typically have ASP. The ASPs in a variety of US markets are tabulated in Table 1 below.

Table 1 – ASP in US markets

US market	**Max scarcity price ($/MWh)**	**Details**
Midcontinent Independent System Operator, Inc. (MISO)	3,500	In the event that operating reserves are depleted and energy demand cannot be met, all energy and operating reserves will be priced at the Value of Lost Load, currently set at $3500/MWh
New York Independent System Operator, Inc. (NYISO)	2,775	The energy offer cap is $1,000/MWh, so in a shortage energy prices should reach that level, and may also rise to higher price levels to reflect the additional shortage prices for reserves.So for a shortage of energy on Long Island could yield energy prices of up to $2775/MWh.
PJM Interconnection, L.L.C. (PJM)	2,700	Emergency demand response, when called upon, leads to the highest possible energy price.
Southwest Power Pool, Inc. (SPP)	50,000	SPP maintains a $50,000/MW "Global Power Balance" Violation Relaxation Limit, meaning it will redispatch its system no matter the cost, up to and including $50,000/MW in order to avoid load-shedding due to a lack of energy available to balance resources and load.
Electric Reliability Council of Texas (ERCOT)	9,000	The Operating Reserve Demand Curve slopes upwards starting at 5000 MW of reserves before becoming vertical at 2,000 MW and is capped at Value of Lost Load, which is currently set at $9000.
ISO New England Inc. (ISO-NE)	2,350	The energy offer cap is $1,000/MWh, so in a shortage energy prices should reach that level, and may also reflect that the reserve products are short as well, so (the energy component of) energy prices could reach $2,350/MWh during an energy shortage.
California Independent System Operator Corporation (CAISO)	1,000	A Shadow Price of $1000 for Regulation-Up is possible when there is a shortage of Regulation-Up and Spinning Reserve, as well as a Non-Spinning Reserve shortage greater than 210 MW

GB ASP and the internal electricity market

3.2.62 The direction of flows on the interconnectors with GB will have a significant impact on I-SEM system security, as there is a potential 2GW swing (from importing 1GW to exporting 1GW), which will depend on relative prices in the real time I-SEM and GB markets. Whilst this may not be very material for GB, this 2GW swing represents around 30% of likely I-SEM peak demand in 2017.

3.2.63 Whilst the harmonised arrangements for cross-border balancing are still under development, as noted above, GB is introducing an ASP floor into its energy BM. The absence of ASP in the I-SEM energy BM could lead to outflows of I-SEM generation at times of coincident system stress, if the I-SEM does not have ASP too. Moreover, to the extent that a probability weighted expectation of scarcity is priced into markets ahead of delivery, a difference in market design could also affect flows intra-day and day-ahead.

3.2.64 In this context the RAs will continue to explore with their GB counterparts the detail of arrangements for times of coincident scarcity.

Summary

3.2.65 It is important for system security that capacity providers face strong incentives to be available and generate at times of scarcity. It is also important that Suppliers face fully cost reflective incentives to reduce load at times of scarcity. These objectives can only be achieved if scarcity is reflected in energy prices.

3.2.66 The SEM Committee believes that the introduction of ASP is necessary to ensure that energy market prices reflect scarcity. Evidence from other countries suggests that market prices do not always rise to reflect scarcity, and policy makers often intervene to implement ASP even in markets without price caps. If market power controls are implemented in the I-SEM this further enhances the case for having ASP.

3.2.67 ASP in the energy market promotes four key I-SEM objectives in a way that the other options considered, such as introducing scarcity pricing in the CRM incentive regime do not. These four objectives are improved system security, efficiency, environmental and Internal EU electricity market objectives.

Definition of scarcity

3.2.68 The SEM Committee has decided that the trigger for Administrative Scarcity should be when there is insufficient available capacity for the TSOs to cover the combination of demand and the target level of operating reserve.

3.2.69 The key reason for this decision is that it provides stronger signals to make plant available at times when capacity is scarce prior to load shedding (Administrative Scarcity triggered only in the event of load shedding). As a result, the definition which includes reduced operating reserve due to insufficient available capacity better promotes System Security. Note that Administrative Scarcity will not apply where operating reserve is reduced below target levels because the TSO uses reserve which has already been deployed (for instance to cover a forced outage), but additional capacity is available to replenish reserve.

3.2.70 The decision to introduce ASP when the I-SEM has insufficient capacity to meet target operating reserve also mirrors to some extent the approach adopted in GB, where a form of ASP applies when the System Operator calls on the Short Term Operating Reserve (STOR) contracts, to prevent load shedding. In GB, when the STOR contracts are utilised, the imbalance price reflects the product of the Administrative VoLL and the Loss of Load Probability. Therefore, if there is a period when both systems are close to exhausting reserves but have not yet had to resort to load shedding the I-SEM will have ASP, like the GB market. Therefore the approach of applying ASP when reserve is reduced better promotes the EU Internal Market objective and ensuring that the CRM does not distort energy market coupling and cross border trade.

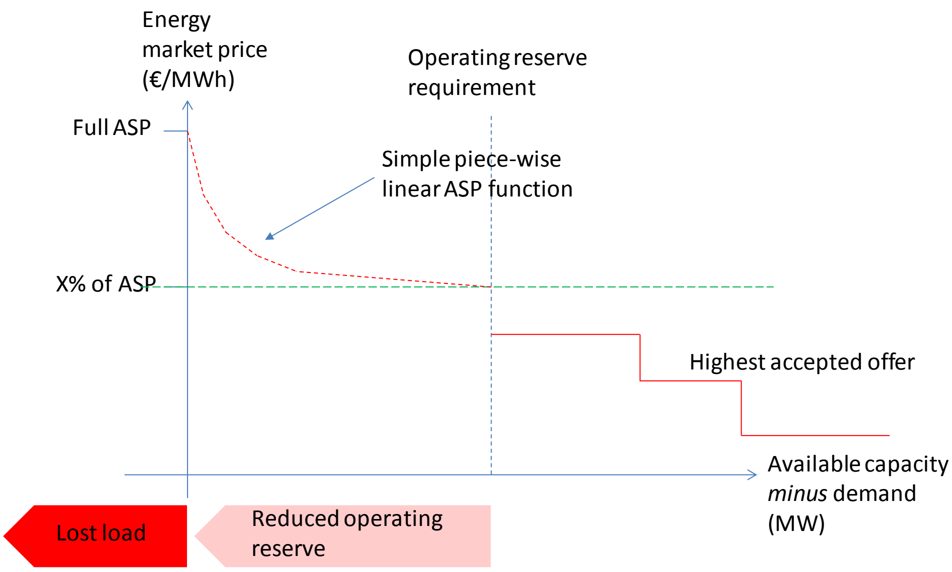
3.2.71 At times of load shedding, the Full ASP will apply. During periods when operating reserves have been reduced below the target level due to insufficient capacity, but load shedding has not occurred, the ASP will be set at a lower level.

3.2.72 The SEM Committee considered a number of options for how the lower level ASP could be determined. These options included:

- Using a Loss of Load Probability (LoLP) x Full ASP;
- Using a simple two-tiered ASP whereby the price during reduced operating reserve is an administratively determined % of the Full ASP; and
- A simple-piece wise linear function.

3.2.73 It is necessary to reflect this piece-wise linear approach in the associated systems implementation currently underway and the RAs will request that the systems be developed to cope with up to a piecewise linear function (with a minimum of five steps). The parameters for the function will be considered as part of CRM Consultation 2, and will be set by the SEM Committee. This approach is illustrated in Figure 9 below. The simple linear function achieves an appropriate balance between cost reflective pricing, simplicity and avoiding spurious accuracy.

Figure 9: Simple linear Administrative Scarcity Pricing function



3.2.74 At any given time the BM price shall be the higher of the BM price absent the ASP and the simple linear function, i.e. the BM will not be depressed below market determined levels because there is an accepted offer greater than the piece-wise linear function.

3.2.75 If BM prices do not naturally rise to reflect scarcity prior to load shedding, the key risk with the planned approach is that it is likely to lead to more events of scarcity and high ASP, with resultant increased risk to Suppliers. However:

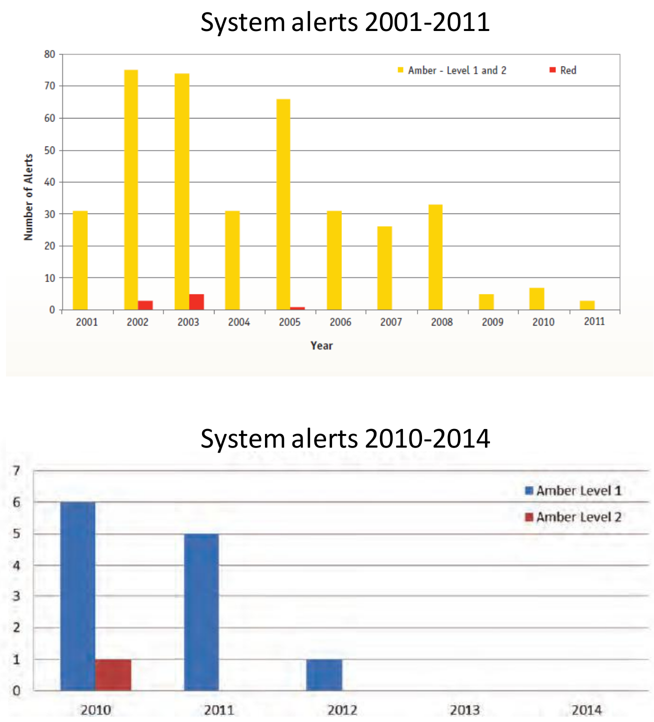
- Suppliers will also have the opportunity to benefit from reducing load and selling back power into the IDM or BM, at these times;
- As discussed in Section 3.7, the SEM Committee decision to implement Option 4b for the MRP and to guarantee to socialise any shortfall in RO difference payments, mitigates the risk to Suppliers.

3.2.76 The data presented in Figure 10: incidences of amber and red alerts 2001-2014 illustrates how often incidences of amber 1, amber 2 and red alerts[28] have occurred historically in the period 2001-2014, based on data provided by Eirgrid. The top diagram shows the breakdown of alerts into amber and red alerts, over the period 2001 to 2011, without being able to establish the break of amber alerts between amber 1 and amber 2. The lower diagram illustrates the breakdown of amber alerts into amber 1 and amber 2 alerts in the period 2010 to 2014- a period in which there have been no red alerts.

3.2.77 Further work will be required to define the target level of operating reserve and to reflect the definition in the Trading & Settlement Code, but broadly speaking we would expect an incident of full load shedding (when the full ASP applies) to correspond to the Eirgrid red alerts, and the reduced operating reserve threshold to be a reasonable approximation to events predicted by an amber level 2 alert.

[28] AMBER ALERT - LEVEL 1: issued by the NCC when a single contingency, such as the tripping of the largest set, would give rise to a reasonable possibility of a failure to meet the system demand and/or the frequency or voltage departing significantly from normal; and/or when multiple contingencies are probable because of thunderstorm or high wind activity. AMBER ALERT - LEVEL 2: issued by the NCC when the system margin, which is the available plant less the predicted peak demand, is less than the primary spinning reserve requirement. RED ALERT: issued by the NCC when: 1. The system frequency deviated significantly from normal; 2. System voltages have deviated significantly from normal; 3. Consumer load has been shed; or, 4. In the period immediately ahead there is a high risk of failing to meet system demand or maintaining normal voltage and frequency.

Figure 10: incidences of amber and red alerts 2001-2014



Source: Eirgrid

3.2.78 There have been no incidences of red alerts since 2005, and there has been only 1 incidence of an amber level 2 alert since 2012, and only 12 incidences since 2010. Whilst the above data relates to number incidences of alerts, and not the number of hours of lost load, it is likely that this data indicates the incidences of actual lost load have been significantly less than the security standard in the last few years.

3.2.79 There are two reason to believe that there may be more frequent incidences in future:

- The period since 2008 is a period following a severe recession when there has been excess capacity, with total peak demand in the SEM falling from a peak of just under 7,000MW in 2007 to a low of just under 6,600MW in 2013, and not increasing much in 2014;
- The existing CRM has weak signals for capacity exit. The existing CRM spreads the Annual Capacity Payment Sum over any generator which provides capacity, and has no limit on the MW of capacity paid for. This may encourage old inefficient capacity to remain on the system. As the CRM moves to procuring a pre-defined volume requirement, rather than spreading payments more over all available capacity, stronger exit signals can be expected.

3.2.80 Whilst this may lead to more incidences of reduced reserve and hence of ASP in future, we note that:

- This strengthens the case for reflecting any increased probability of lost load in early price signals before actual load shedding;

- The RO, combined with our proposal to "socialise" any shortfall in RO difference payments (see Section 973.7) will protect Suppliers from the extremes of price exposure whilst still providing them with the full marginal incentive to reduce consumption and sell back power into the market at the ASP, before scarcity occurs.

Level of Administrative Scarcity Pricing (ASP)

3.2.81 The SEM Committee will consult further on the appropriate level for the Full ASP to apply in the event of load shedding, as well as the level of ASP during reduced operating reserve. The following paragraphs outline some of the key considerations that will need to be accounted for in making this decision.

3.2.82 One respondent raised a point that the I-SEM DAM price cannot rise higher than the Euphemia cap of €3,000/MWh. An argument was made that there is a potential incentive on generators to withhold power from the DAM to sell into the IDM or BM, if:

- The ASP is significantly higher than €3,000/MWh; and
- Generators perceive that there is a high probability that there will be load shedding, so that the probability weighted expectation of the BM price or the IDM prices significantly exceed €3,000/MWh.

3.2.83 This incentive will not apply to generation covered by the RO, given that Option 4b (split market price) applies for the MRP. Under Option 4b, any value which the RO generator receives above the Strike Price (which will be lower than €3,000/MWh) will be returned to Suppliers via the RO difference payments[29]. However, this incentive would still apply to any capacity not contracted through ROs, including any difference between "de-rated" capacity and "nameplate" capacity and capacity which opts out of the CRM bidding (which intermittent renewable generation and non-firm transmission access generation will be allowed to do - see Section 4.3 and 4.4).

3.2.84 A request was made to consider introducing ASP at a lower level during a transition period, to limit the risk to market participants when there is significant change to the energy, capacity and DS3 System Services happening at the same time.

3.2.85 As described above, the SEM Committee will consult further in CRM Consultation 2 on the appropriate level of full ASP, and whether the full ASP should be set at a lower level during a transition period after I-SEM go-live.

3.2.86 The SEM Committee, in consultation 2, will also consider:

[29] If Option 3 for the MRP was adopted, the RO would not remove the incentive on generators to withhold power from the DAM, as they would receive the full ASP on their BM and IDM sales, and not have to pay back any amount above the RO strike price received on BM and IDM sales.

- The precise definition of load shedding. The SEM Committee recognises that there are different ways in which the TSO can manage insufficient capacity including reducing frequency and/or voltage as well as cutting off customers[30].
- The level of full ASP to be used and whether it is appropriate to set the full ASP at a lower level for a short period after the I-SEM is introduced.
- Setting the piece-wise linear function, as illustrated in Figure 9. We recognise that the maximum number of maximum inflexion points needs to be reflected in a system specification, as a matter of priority, and we will request that the system specification contains the capability to deal with a 5 piece linear function (i.e. has up to a maximum of 4 inflection points).

Impact on Suppliers' risk

3.2.87 The SEM Committee have considered the impact on Suppliers of introducing ASP which could potentially increase spot market volatility, relative to a counterfactual in which there is no ASP, and in which prices do not rise to reflect scarcity to the extent expected in a well functioning market.

3.2.88 The SEM Committee have considered the risk to non-vertically integrated Suppliers, and vertically integrated suppliers who are net buyers in the wholesale market, who do not have higher generation revenue to potentially offset higher Supply costs, if there is a price spike. The design of the proposed RO, with the split MRP serves to limit the risk to Suppliers by ensuring that their exposure is capped at the RO Strike Price in all physical energy markets (the DAM, IDM and BM). Further consideration of Supplier risk is provided in Section 3.7.

Impact on Capacity Providers risk and auction bids

3.2.89 A number of stakeholders argued that the introduction of ASP would increase the risk to capacity providers of having to make large RO difference payments, and that this risk would be priced into auction bids.

3.2.90 The SEM Committee notes that this risk only arises in the event that a capacity provider does not deliver at times of scarcity and considers this an important component of the incentive to deliver capacity during these times. Capacity providers will only face this risk when their plant does not deliver its contracted de-rated availability. When the plant is genuinely available, it will be able to earn the ASP to offset the difference payments. It is appropriate that less reliable plant (in relation to its de-rated capacity) should reflect the greater risk that it faces in its auction bids - which would make the plant less competitive in the auction than an equivalent plant of greater reliability. Whilst this may lead to the auction clearing at a higher price in the

[30] Clearly to the extent that demand side management is scheduled through the CRM, this would not count as load shedding

short term than it would otherwise have done, this will act as an incentive for market entry and exit. This will lead to greater confidence that appropriately reliable plant is being procured, and unreliable plant is not being over-contracted, ensuring greater system security. A higher clearing price would also create an incentive for new, more efficient plant, to potentially enter the market.

Interaction between energy, capacity and DS3 System Services

3.2.91 The SEM Committee agrees that, in principle, in a well-functioning set of energy, capacity and DS3 System Services, that market prices will rise naturally to scarcity levels. However we note that:

- In practice, there are continuing market power issues in the All-Island market, which require controls on market power;
- ASPs are a "price of last resort", and do not prevent prices rising to scarcity levels of their own accord, where market power controls do not bind, or where there is sufficient price responsive demand.

3.2.92 We are designing the CRM and DS3 System Services with the intent of avoiding unintended consequences, such as double payment, which was a concern for one respondent. We believe that the risk of unintended consequences is manageable through the detailed design and implementation phase, including through the use of working groups, as appropriate.

SEM Committee Decision

3.2.93 The SEM Committee has made the following key decision regarding ASP:

- **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 TSO uses 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 Paper (SEM-15-064).

Next steps

3.2.94 The RAs will consult further, in Consultation Paper 2 on:

- The appropriate level for the Full ASP;
- Whether it is appropriate to have a phased approach to introduction of ASP, introducing ASP at a lower level during some transition period;
- The precise definition of load shedding- i.e. when the Full ASP will apply;
- The precise definition of target operating reserve requirement. .

3.2.95 The RAs will explore further with GB counterparts the detail of arrangements for times of coincident scarcity.

3.3 MARKET REFERENCE PRICE

Consultation Summary

3.3.1 SEM-15-044 set out six key options for the MRP, namely:

- Option 1: BM price:

- Option 1a: BM price without scarcity pricing;
- Option 1b: BM price with scarcity pricing;

- Option 2: 100% Intra-Day Market (IDM) price;
- Option 3: 100% DAM price;
- Option 4: Multiple reference market option:

- Option 4a: A blended price option, where the market price is a weighted average of DAM prices;
- Option 4b: A split market price option.

3.3.2 The consultation paper set out the RAs' preliminary view on the pros and cons of each option, and asked for feedback.

3.3.3 The consultation paper also discussed whether the RO should payout at any time when the MRP exceeds the Strike Price (a price based trigger), or only when the MRP exceeds the Strike Price *and* administrative scarcity has been declared. The following discussion of the MRP is in the context of the decision that the RO will pay out on a purely price based trigger, not a scarcity based trigger, and this decision is explained in paragraphs 3.3.94 to 3.3.94.

3.3.4 Further clarification of the leading options, and the difference between them, were presented at a public seminar in Dundalk after the issue of SEM-15-044. Whilst Options 1, 2 and 3 are conceptually relatively straightforward, with cashout against a single price, more explanation was provided around Option 4b, which involves the use of multiple reference prices. Note that as discussed in paragraph 3.3.46, Option 4a did not score well in the evaluation and was not discussed further.

Further description of Option 4b (split market option)

3.3.5 Under this option 4b (split market price option) capacity providers' Reliability Options will be settled on:

- Volumes sold in the DAM at the DAM reference price;
- Volumes sold in intra-day markets at the intra-day MRP(s); and
- Any remaining Reliability Option volume[31] at the BM reference price.

3.3.6 In the event that the sum of capacity provider's DAM and IDM volumes sold exceed its RO volume, DAM volumes will be taken into account first, and then each IDM trade (or part trade)[32] progressively in the order in which they were executed, until the volume of sales equals the RO volume. All other things being equal, this provides the incentive on capacity providers to make their volumes available earlier rather than later during a potential stress event, reducing the likelihood of lost load. The same split market RO settlement will apply to Suppliers, with volumes bought in the DAM settled with reference to the DAM price, volumes bought in the IDM settled with reference to the IDM price(s) and BM volumes settled with reference to energy imbalance prices[33].

Worked example to illustrate difference between leading options

3.3.7 The following simplified worked example illustrates how supplier and generator payments would differ under the leading options 1B, 3 and 4B.

3.3.8 Let us assume there are three generators, A (100MW baseload), B (100MW mid-merit/peaking) and C (50 MW wind). Let us assume that A and B both have 90MW of RO at a Strike Price of €500/MWh.

3.3.9 For a given 1 hour settlement period t, let us assume that at the Day Ahead stage, forecast demand is assumed to be 150MW, with Suppliers E expected to consume 70MW and Supplier F expected to consume 80MW.

3.3.10 Assume that:

- A has 50MW of availability, which it sells into the DAM;
- C is expected to produce 30MW of wind, which it sells into the DAM;
- B makes up the residual volumes selling 70MW into the DAM;
- There is no scarcity and the DAM price is 100MW.

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[31] After taking appropriate account of the load following adjustment- see Section 3.5

[32] If a 100MW generator has 90MW of RO, with a Strike price of €500 and sells 80MW in the DAM at €100/MWh and 20MW at €1,000/MWh the first 80 MW will be settled against the DAM trade and it will pay nothing. 10MW of the 20MW IDM trade will count against the remaining 10MW of the RO, so it will pay 10MW x (1,000 – 500)

[33] i.e. where a Supplier buys 100MWh in the DAM at €100/MWh and 20MWh at €700 in the IDM at €1,000/MWh and 5MWh in the BM at €10,000/MWh, if the Strike Price is €500/MWh, then the Supplier receives nothing on the DAM volume (1,000-500)x 20 on the IDM volume and (10,000 – 500) x 5 on the BM volume

3.3.11 Now assume that at delivery, demand increases to 180MW causing scarcity, due to an increase in 31MW of demand from Supplier E, although let us assume that Supplier F responds to the scarcity by reducing its customers' consumption by 1MW. Assume that C actually generates 40MW of wind output, and B increases its output to 90MW, with the additional output from B and C being sold in the BM. The scarcity price is assumed to be €10,000/MWh.

3.3.12 We now illustrate how capacity provider and supplier payments differ under Options 4b, 3 and 1b.

Assumptions	
RO Strike Price	500
Day Ahead Market Price	100
BM price	10000

Capacity provider	Nameplate	ROQ	EAQ	MQ
A	100	90	50	50
B	100	90	70	90
C	50	0	30	40

	Energy market trades		RO	
	Ex ante	BM	Diff payments	Total
Option 4b Split market				
A	€5,000	€0	-€380,000	-€375,000
B	€7,000	€200,000	-€190,000	€17,000
C	€3,000	€100,000	€0	€103,000
Option 1 BM				
A	€5,000	€0	-€855,000	-€850,000
B	€7,000	€200,000	-€855,000	-€648,000
C	€3,000	€100,000	0	€103,000
Option 3 DAM				
A	€5,000	€0	€0	€5,000
B	€7,000	€200,000	€0	€207,000
C	€3,000	€100,000	€0	€103,000

Supplier	Deemed ROQ	EAQ	MQ
E	101	70	101
F	79	80	79

Option 4b (split market)

	Ex ante trades	BM payments	RO diff payments	Total
E	-€7,000	-€310,000	€294,500	-€22,500
F	-€8,000	€10,000	€0	€2,000

Option 1b (BM)

	Ex ante trades	BM payments	RO diff payments	Total
E	-€7,000	-€310,000	€959,500	-€642,500
F	-€8,000	€10,000	€750,500	€752,500

Option 3 (DAM)

	Ex ante trades	BM payments	RO diff payments	Total
E	-€7,000	-€310,000	€0	-€317,000
F	-€8,000	€10,000	€0	€2,000

ROQ = Reliability Option Quantity, EAQ= Ex ante quantity, i.e. Day Ahead sold volume, MQ= Metered Quantity, i.e. actual generation output

Option 4b (split market price option)

3.3.13 Now in this case, Generator A has sold 50MW into the DAM, so the first 50MW of its RO is cashed out against the DAM reference price of €100/MWh and no difference payments are due. It earns €5,000 on this 50MW. However, it fails to deliver 40MW of its RO, and this 40MW is cashed out against the BM price of €10,000/MWh, so it has to pay a difference payment of 40 x (10,000 -500) = €380,000. A is therefore heavily penalised via the CRM for failing to deliver on 40MW of RO at a time of scarcity.

3.3.14 Generator B earns €7,000 on its 70MW sold in the DAM, and the first 70MW of its RO is cashed out against the DAM reference price of €100/MWh so no difference payments are due on this volume. It sold 20MW of volume in the BM at €10,000/MWh so earns €200,000 on this volume. However, the RO only pays out above the Strike Price (€500MWh) on this BM volume, so B pays out €190,000 in difference payments.

3.3.15 Generator C, which does not have an RO retains the full scarcity rent on the 10MW of output it sells in the BM.

3.3.16 Supplier E receives a difference payment on the 31MW of its BM purchase at €10,000, which caps its purchase cost on this volume at the Strike Price of €500/MWh. The difference payment is 31 x (10,000 – 500) = €294,500, so the net cost of the incremental 31MW is -€310,000 - €294,500 = €15,500.

3.3.17 Supplier F receives a benefit of €10,000 for responding to the AS P and getting its customers to cut their demand by 1MWh relative to the Day Ahead volume, and this credit of €10,000 is greater than the €8,000 it paid for the 80MWh bought in the DAM at the then prevailing price of €100/MWh.

Option 3 (Day Ahead Market (DAM) price option)

3.3.18 By contrast, under Option 3, because scarcity does not happen until after the Day Ahead stage:

- Generator A is not penalised for failing to deliver 40MW of its RO, and just earns €100/MWh on the 50MW it actually does produce. In Option 3, A makes an overall net revenue of €5,000, whereas in Option 4b it had a negative net revenue of -€375,000 in the settlement period;
- Generator B does not have to pay back any scarcity rents, so makes a total net revenue of €207,000 under Option 3, compared to €17,000 in Option 4b. Whilst it might seem that Option 4b has blunted the incentive on B to increase its output from 70 to 90MW, if B had not increased its output, it would still have had to settle the residual 20MW of its RO at a price of €10,000 if it had not generated the incremental 20Mw and would have had a net revenue of -€193,000, so the marginal incentive on B is the same under both Option- it is just that under option 3 the generator has more upside potential and less downside risk;
- Supplier E pays the full scarcity price on the 31MW it buys in the BM, costing it €310,000 in option 3 compared with €15,500 under option 4b.

Option 1b (BM price option)

3.3.19 Under Option 1b:

- Generator A has to pay out difference payments at (scarcity price – Strike Price) on the full 90MW of RO. Hence it loses money as a result of having sold in the DAM at €100/MWh instead of in the BM at €10,000 and has to payout on the first 50MW of its RO obligation which it has honoured, but not earned scarcity rent on.
- Similarly Generator B loses money because it has to pay out more in difference payments that it has earned on the first 70MW of its RO obligation that it sold in the DAM;

3.3.20 Both Suppliers would earn difference payments on their full consumption, even though, in the case of Supplier F, it has procured all of its energy in the DAM at a price of only €100/MWh. It would earn a difference payment of 79 x (10,000 – 500) = €750,500. Since it paid only €8,000 it would receive a big windfall gain as a result of the scarcity, despite having provided only very modest demand response.

Summary of Responses Received

3.3.21 The majority of respondents expressed a preference for Option 3: DAM price, although some expressed a preference for Option 4b: split market price option, and the TSOs proposed their own variant of Option 1b.

Responses in favour of Option 3 (Day Ahead Market (DAM) price)

3.3.22 The key reasons set out by proponents of Option 3 were:

- A fear that using other markets as the reference could drain liquidity from the DAM;
- It would align with the reference market for CfDs and FTR, and if liquidity were drained from the DAM, this would have negative consequences for liquidity in forward markets;
- It would promote efficient Day Ahead scheduling, including via EUPHEMIA;
- Simplicity, particularly a concern that introduction of other reference markets would complicate hedging ; and
- A belief that it is not necessary to reference the BM in the RO in order to incentivise generators to be available at times of scarcity, and that if the imbalance price is well designed, this should be sufficient incentive to be available at times of system stress.

3.3.23 A number of respondents described how it is important that the MRP avoids distorting energy market bidding behaviour through exposing participants to risks, such as basis risk. A number of respondents stated that it is crucial that the MRP is accessible to capacity providers; otherwise some participants will not be able to hedge risk and will add this cost to their capacity offer prices.

3.3.24 A number of respondents stated that the DAM will be the most liquid market in the I-SEM and choosing the DAM as the reference market would facilitate day-ahead market liquidity. One respondent stated that using a BM related price as part of the RO design would drive liquidity into the BM to the detriment of DAM liquidity. A number of respondents described how referencing ROs to any other market than the DAM could cause significant liquidity issues in both ex-ante, spot and forward contract markets due to basis risk.

3.3.25 A number of respondents stated that the DAM will likely be the reference for many other mechanisms, such as the forwards market. One respondent described how using the DAM as the reference market would give capacity providers the confidence to capture the DAM price to back up their liability, with a full hedge available if CfDs are also written against the DAM. One respondent stated that using the DAM as the reference market simplified the hedging process for generators.

3.3.26 A number of respondents argued how choosing the DAM as the reference market would simplify cross-border trading and facilitate efficient interconnector flows, which will result in benefits such as downward price pressure and reduced wind curtailment.

3.3.27 One respondent argued that the objective of the CRM is to procure long-term capacity adequacy, hence the appropriate reference market would be the DAM, and stated that episodic (short-term) scarcity (as opposed to systemic scarcity)would be best addressed in the BM. Another respondent stated BM design is the place to consider incentives/penalties, while ROs should be about system reliability and hence they should be referenced to the DAM market.

3.3.28 Another respondent stated that if the DAM misses signals related to unforeseen forced outages these scenarios will likely be addressed via the DS3 System Services mechanism by the holder of a System Services contract such as ramping reserve.

3.3.29 A number of respondents did not agree that using the DAM as the reference market may not adequately incentivise capacity providers to be available at times of system stress and argued how incentives are implicit through balance responsibility in the energy market.

3.3.30 A number of respondents referred to the complexity introduced by using a multiple reference market option, and how this option makes the process less transparent and complicates hedging. One respondent argued that potential issues include whether the multiple reference market option will be calculated at a gross or individual provider level, the complexity of verifying participants' positions in the case of a stress event and the relationships between RO and traditional forward hedges.

3.3.31 Another respondent argued that the use of multiple reference markets under option 4 would reduce risk for baseload generators, but would increase risk for mid-merit and peak generators.

3.3.32 One respondent stated its preference for the DAM option was subject to the caveat that measures around market power and liquidity are adopted such that the exposure for suppliers to high BM prices is mitigated insofar as possible.

Responses in favour of Option 4b (split market price)

3.3.33 A number of respondents favoured the split market price option (Option 4b). Those that argued in favour of Option 4b, generally subscribed to the views that:

- Option 4b would not distort bidding behaviour or influence liquidity; and
- A purely DAM reference price would not adequate reflect system stress and incentivise capacity providers to make capacity available at times of system stress.

3.3.34 One respondent described how by including all market timeframes (including IDM) as a reference you avoid draining liquidity from any particular timeframe. This respondent also described how IDM liquidity is vital to wind generators ability to effectively participate in the I-SEM, as it allows for adjustment to updated wind forecasts without incurring the penalties associated with imbalance in the BM.

3.3.35 Another respondent argued that the MRP must incorporate the BM in order to properly capture stress scenarios, properly incentivise RO holders to be available when ROs are called and to deliver the 'price smoothing' benefits cited as a primary objective of the CRM.

Other responses

3.3.36 One submission received from the TSOs favoured the BM with Scarcity Pricing (Option 1b) describing how it will provide the most accurate signals of system stress, a key component of the Reliability Option model. The TSOs described how Option 1b would introduce a degree of basis risk for market participants trading in the day-ahead and intraday markets and proposed an integrated settlement model to eliminate basis risk.

3.3.37 This proposed variant of Option 1b looks to remove one of the key drawbacks of Option 1b, the basis risk for generators if they sell power in the DAM but have to make Reliability Option difference payments based on the BM price by:

- Capping energy imbalance settlement at the RO Strike Price; and
- Paying any additional element of the ASP (or market determined scarcity premium) through a Reliability Imbalance component.

3.3.38 A description of this proposal is included as Appendix G.

Further post workshop feedback

3.3.39 The RAs presented some worked examples of Option 4b at the public workshop held in Dundalk on 28 September 2015. The worked examples compared the incentive effects of Option 3 and Option 4b, and illustrated how Option 4b could work in conjunction with two-way CfDs. Spreadsheets underlying the worked examples were also circulated.

3.3.40 The RAs received further representation from certain stakeholders in relation to Option 4b following workshop. Key points made include the following:

- Some respondents asked for more time to consider the incentive effects of Option 4b;
- One respondent argued that since the I-SEM will not be a pure self-dispatched market, a capacity provider could not guarantee that it would be dispatched to earn energy market revenue to offset any liability to make RO difference against a BM price. In particular, they were concerned that the lack of self-dispatch would make it difficult for them to ramp up to their RO volume, if they were scheduled at lower volume in the DAM auction;
- Some stakeholders re-iterated concerns about the general level of complexity in the design of the MRP and its potential impact on liquidity;

- The worked examples presented in Dundalk led in one example of a surplus of funds being collected (in the case whereby scarcity was caused, at least in part by a generator outage). It was argued that the as a general principle, if funds did not balance, then it was not possible for potential gainers and losers to come together and hedge the risk, and the gainers would have insufficient funds to hedge the losers;

3.3.41 Some stakeholders recognised the points made by the RAs at Dundalk about the lack of incentives contained within Option 3, but made representation that it would be possible and simpler to penalise generators who fail to deliver through a system of additional performance incentives, overlaid on top of Option 3 and/or regular availability testing. They argue that such an approach would interfere less with the physical energy market and forward financial contracting around the energy market. Under this approach, capacity providers would face a financial penalty if they failed to deliver, in addition to making RO difference payments against a DAM reference price.

SEM Committee response

Overview

3.3.42 The SEM Committee is of the view that, on balance, Option 4b best promotes the key I-SEM objectives. The key factors are:

- **Security of supply**: it better promotes the objective of security of supply by ensuring that only reliable capacity is rewarded, and unreliable capacity which fails to deliver at times of system stress cannot have a “free bet” that it will not be required; and
- **Competition**: The RO, with the incorporation of Option 4b, can serve to cap the exposure of Suppliers to high prices on unexpected volume changes at the RO Strike Price, and operates across all physical markets in which the Supplier can buy power. This supports the RAs’ objectives of promoting competition among Suppliers.

3.3.43 Of the options considered, Option 1a, the original version of Option 1b and Option 2 would disincentivise capacity providers from bidding into the DAM, because of the basis risk they face between the DAM price and the MRP. The basis risk arises because of a potential risk of having to settle against a BM and/or IDM price which reflects scarcity, when they have sold power in the DAM at a lower price, prior to scarcity having arisen. Any option that strongly disincentivises capacity providers to bid into the DAM at times of potential scarcity is sub-optimal for a number of reasons. For example, withholding power from the DAM decreases efficiency by increasing the risk of sub-optimal dispatch due to inter-temporal constraints. These options also fail to promote liquidity and competition in the key I-SEM physical market, and potentially distort international trade based on the Euphemia day-ahead algorithm.

3.3.44 Options 3, 4 and the Eirgrid variant of Option 1b protect the capacity provider against this basis risk, and were given significant consideration.

3.3.45 The SEM Committee accepts that Option 4b is more complex than Option 3, but thinks that the additional complexity is justified to better promote security of supply and competition in supply.

3.3.46 Option 4a was rejected because it has the additional complexity of option 4b, but without material benefits relative to Option 3.

3.3.47 The SEM Committee also considered the Eirgrid variant of Option 1b, but discounted it, primarily because it caps the marginal energy price that Suppliers can earn by selling back into the BM at times of scarcity, and hence does not deliver sharp incentives for load reduction.

3.3.48 In the remainder of this Section we set out in more detail the SEM Committee's view of the pros and cons of Option 4b versus Option 3 and the Eirgrid variant of Option 1b, before addressing some of the specific issues raised by stakeholders with respect to Option 4b.

Why Option 4b better promotes objectives than Option 3

3.3.49 There are two key reasons why Option 4b better promotes the key I-SEM objectives than Option 3. Firstly, it is provides incentives for capacity to be reliable by penalising capacity providers which do not make themselves available at times of system stress. Secondly, it provides Suppliers' with protection against extreme BM prices, facilitating competition in Supply. We discuss each of these points in turn below.

3.3.50 The SEM Committee recognises that there are some drawbacks associated with Option 4b, including some (but not all) of the issues raised by stakeholders and discussed in paragraphs 3.2.30 to 3.2.31. In addition, the choice of Option 4b, increases the likely interaction between penalty caps and capacity providers incentives to sell forward in the DAM, which is discussed in paragraphs 3.3.5 to 3.3.6.

3.3.51 However, on balance, the SEM Committee thinks that relative benefits of Option 4b, i.e. the two key reasons discussed below, outweigh the relative disadvantages.

Incentivising reliable capacity

3.3.52 The introduction of Administrative Scarcity Pricing in the energy market goes a significant way to incentivising any capacity provider that can make its capacity available at times of system stress, to make its capacity available to earn the scarcity price. However, Option 3 permits a gaming opportunity for unreliable generators.

3.3.53 A key concern is that Option 3 would allow generators with unreliable capacity to bid into the auction, obtain capacity payments and pursue strategies to avoid any adverse consequences when they do not deliver. In effect this would be a free bet for generators who could profit from low cost "iron in the ground".

3.3.54 If a generator knows that it cannot deliver on its capacity obligation and does not bid into either the DAM or the BM then Under Option 3, the generator :

- Is not at risk from having to buy back generation outages at high BM prices in the event of scarcity; and
- Will not be materially exposed to RO difference payments, since international experience suggests that scarcity rarely if ever happens in Day Ahead timescales, the DAM price will rarely if ever exceed the RO Strike Price.

3.3.55 By contrast, a generator pursuing this strategy under Option 4b would be heavily penalised in the form of RO difference payments settled against the BM, which reflects scarcity, without having any offsetting BM revenue. The behaviour of Generator A in the worked example in paragraph 3.3.12 is an example of such a strategy.

3.3.56 As discussed above, some stakeholders made representation that it would be possible and simpler to penalise generators who fail to deliver through a system of additional performance incentives, overlaid on top of Option 3 and/or regular availability testing.

3.3.57 The SEM Committee does not rule out availability testing, but notes that availability testing can prove expensive for consumers, and whilst it may catch the most egregious example of unreliable capacity, it will not incentivise capacity providers to price degrees of unreliability into their auction bids. Availability testing needs to be supplemented with additional incentives, which penalise unreliable capacity providers in proportion to the cost their unreliability imposes on other market participants- i.e. at ASP if scarcity occurs.

3.3.58 In principle, it would be possible to overlay a system of additional incentives on top of Option 3, which would charge a capacity provider which failed to deliver on its RO volume at the ASP. However, if the penalty rate for under-delivery is the ASP, such an approach runs the risk of "double penalising" capacity providers, as per the example below.

3.3.59 Consider the case of a Generator A, which has 100MW of nameplate capacity and 90MW of RO contracted volume. Lets us assume that at Day Ahead stage, scarcity is not expected and the DAM price is €100/MWh. Lets us assume that A expects to be fully available a sells its full nameplate capacity forward into the DAM. Lets us assume however, that Generator A has partial outage of 40MW, which combines with other factors to cause scarcity and Generator A is cashed out on its 40MW outage in the BM at an ASP of €10,000/MWh. If it is also penalised via CRM at €10,000 on its 30MW shortfall versus its RO obligation, then it is double penalised on this volume. By contrast Option 4b, by settling the full 90MW of RO volume that Generator A sold into DAM at the DAM price, ensure that the combine impact of the energy and capacity market is to charge Generator A only once for its non-delivery against its RO commitment.

Competition in Supply - Protecting suppliers against price spikes

3.3.60 Option 4b provide Suppliers with a hedge on BM and IDM price exposure which the market is unlikely to otherwise provide, and which Option 3 would not provide them with.

3.3.61 Consider the case of a Supplier E in the example set out in paragraph 3.3.12. At Day Ahead stage, E expects to have 70MW of demand from residential customers and procures this volume in the DAM at €100/MWh. Subsequently the day is unexpectedly cold, and this combined with other factors causes Supplier E's demand to grow to 101MW and scarcity to occur. Under Option 4b, Supplier E will receive a difference payment on the 31MW procured in the BM at €10,000/MWh. Assuming that the Strike Price is €500/MWh, Option 4b caps Supplier E's exposure on the unanticipated customer demand at €500/MWh. By contrast, under Option 3, Supplier E would have been cashed out against the BM price of €10,000/MWh on all the 31MW of volume procured in the BM. This cap on its exposure significantly reduces the risk that a single incidence or limited number of incidences of mis-forecasting can cause E material financial distress.

3.3.62 This protection is more important for non-vertically integrated Suppliers or for vertically integrated Suppliers that are net buyers, than for fully vertically integrated utilities. For example, if Generator B in the example presented in paragraph 3.3.12 was the generation business unit of Supplier E, then under Option 3, it would have 20MW of BM sales at €10,000/MWh which would have substantially offset the loss made by Supplier E on the 31 MW of sales.

3.3.63 A fully vertically integrated utility is likely to benefit from this "natural hedge"-i.e. there is a significant probability that a price spike which causes losses in its Supply business is offset by increased profit in its Generation arm, particularly where the price spike is caused by the ability to earn scarcity rent, not by an increase in variable fuel cost. A non-vertically integrated supply business, particularly a small new entrant with a weak balance sheet, is typically more vulnerable to a price spike. Whilst the introduction of ASP may increase the vulnerability of Suppliers, Option 4b caps the price exposure in the DAM, IDM and BM.

3.3.64 A hedge against real time BM prices and IDM prices via the RO is likely to be important in the context of a move from the SEM to the I-SEM. In the SEM CfDs are struck against ex-post Pool prices. Assuming that other I-SEM hedging instruments, such as CfDs and FTRs will be struck against the DAM price, the move to the I-SEM will mean that Suppliers will not otherwise have access to a hedge against the real time price- something they do in the SEM.

3.3.65 Note that Option 4b provides a hedge to BM exposure. Such hedges are not readily available to Suppliers in the GB or other many other European markets. For instance, in the GB BETTA market, where there is no significant liquidity in volume flexible BM call options (which is what the RO provides under Option 4b), so non-vertically integrated Suppliers are not able to hedge themselves against BM price spikes. This arguably gives vertically integrated utilities a competitive advantage.

3.3.66 The cap on Supplier's BM exposure in Option 4b comes at the cost of blunting some incentives on Suppliers, since Supplier E only faces a marginal cost of €500/MWh on its incremental BM purchase, rather than an incremental cost of €10,000/MWh that it would have done under Option 3. However:

- Suppliers whose customers can provide a degree of demand response, such as Supplier F in the worked example in paragraph 3.3.12, face the full marginal incentive to reduce consumption below the DAM purchase volume and sell it back into the energy market. In the example above Supplier F receives the full €10,000/MWh on its demand response of 1MW;
- The SEM Committee is of the view that the benefits of protecting Supply competition outweigh the cost of blunting some wholesale market marginal incentives;

3.3.67 During further engagement some stakeholders, mostly generators or vertically integrated utilities, have argued that it is not appropriate to cap a supplier's exposure to BM prices through the RO design, and that it is appropriate that Suppliers who mis-forecast their demand at Day Ahead stage should face the full real time market price, including the ASP. Whilst in principle, the SEM Committee agrees that Suppliers should have incentives to forecast accurately and should face the full marginal cost of their actions, these objectives need to be balanced against the SEM Committee's objective to promote Supply competition, including from non-vertically integrated Supply businesses.

Why Option 4b better promotes objectives better than Eirgrid variant of Option 1b

3.3.68 The SEM Committee welcomes the contribution the TSOs made to the analysis of MRP options, and has given significant consideration to their proposed variant of Option 1b, which removes the basis risk issue faced by the original version of Option 1b. However, on analysing this variant of Option 1b the SEM Committee found that:

3.3.69 The marginal incentives on Suppliers to reduce load are much less strong in Option 1b than they are in Option 4b, since any Supplier reducing its customer's demand will be capped at the RO Strike Price on the price it receives on any DAM volume sold back in the BM; and

3.3.70 The Eirgrid variant of Option 1b leads to capacity providers being exposed to a "Reliability Imbalance" in addition to the Day Ahead price for merely honouring their DAM commitment. This is a significant departure from the normal settlement approach in two-settlement markets, and different to that employed in other European markets such as NordPool and BETTA.

3.3.71 In addition, it is not clear how limits on BM cashout in the TSOs' variant of Option 1b might impact on cross-interconnector trade, as the EC moves towards more integrated real time optimisation of the interconnector.

Other comments raised in relation to Option 4b

3.3.72 We address a number of issues raised by stakeholders with regard to perceived features of the Option 4b design under the following headings below:

- Impact on marginal incentives;
- Instances whereby a capacity provider, particularly an inflexible one, may be exposed to the risk of making difference payments, but without being able to earn energy revenues;
- Surplus recovery, unhedgable risks and risk management;
- Impact on incentives to trade in physical markets (DAM, IDM and BM);
- Impact on liquidity and incentives to trade in forward financial markets.

Impact on marginal incentives

3.3.73 Some respondents, having analysed the worked examples presented at the stakeholder workshop on the 28th September in Dundalk, have questioned whether Option 4b provides the right marginal incentives and have pointed out that in the worked examples shown in Dundalk:

- Supplier's price exposure is capped at the RO Strike Price; and
- Increments in generation output were not always rewarded at the Full ASP through the CRM.

3.3.74 It is correct that Suppliers do not face the full ASP on incremental consumption, with their price exposure on DAM, IDM and BM purchases capped at the RO Strike Price. However, as discussed above, the SEM Committee thinks that capping Suppliers' exposure strikes an appropriate balance between limiting risks to Suppliers (and hence promoting Supply competition) and providing the right price incentives to reduce consumption.

3.3.75 The RAs have analysed Option 4b, and are content that the combined impact of the energy market and the capacity market design does provide the right marginal incentives on generators. In some case, e.g. where a generator has an outage, it is the energy imbalance market, which incorporates the ASP, which provides the right incentive, rather the CRM *per se*. The SEM Committee considers that it is important that the two markets operating in conjunction combine to provide the right effect, and the capacity market should not duplicate incentives where they are fully present in the energy market.

Surplus recovery and risk management

3.3.76 RO difference payments from capacity providers do not always equal RO difference payment to suppliers. One respondent has suggested that this is a function of adopting Option 4b, and that the “surplus recovery” removes money from the market and makes it impossible to manage certain risks in this market.

3.3.77 The “surplus recovery” occurs when scarcity is caused by a generator outage, and that generator is replaced by another generator. The first generator has to buy back its outage in the balancing or intra-day market at the scarcity price, effectively from the second generator who earns scarcity rents. The second generator has to make an RO difference payment which removes the scarcity rents from it, but this difference payment is not used to limit the first generator’s cost of buying back its outage in the BM/IDM. The fact that the first generator’s exposure is not capped is the source of its incentive to be reliable, but leads to surplus recovery, with the benefit being socialised back to Suppliers.

3.3.78 It has been argued that this surplus recovery means that there is no agent who has an equal and opposite exposure to the first generator so there is no agent who can provide the generator with outage insurance, which creates inefficiency in the market. Whilst this is true, the SEM Committee is of the view that:

- Capacity providers should face strong incentives to perform, and to extent that their exposure is limited, it will be through limits on RO difference payments- see Section 3.6 .
- There are few, if any, examples of a market in outage insurance evolving between electricity wholesale market participants (as opposed to being insured by insurers), and no such market has emerged between SEM participants. Therefore this is largely an academic concern.

Concerns that capacity providers will not be receive energy payments to offset their difference payment liabilities

3.3.79 We received representation from a number of stakeholders concerned that there may be occasions when they may be subject to a requirement to make difference payments but may not be able to generate due to circumstances beyond their control.

3.3.80 The SEM Committee wishes to make it clear that capacity providers who are providing reserve or other system services in accordance with TSO instruction will have the relevant part of their RO commitment settled with reference to their reserve/system services income.

3.3.81 It was commented that the I-SEM is not a self-dispatched market, so a generator cannot be guaranteed to be scheduled in the settlement periods prior to a likely scarcity event, if demand in those periods is lower than the nearby peak during which scarcity is expected to occur. If the plant is not sufficiently flexible, the plant may not be able to ramp up to its full RO volume in time, and hence may be exposed to RO difference payments without the full offsetting energy revenue.

3.3.82 Whilst such as eventuality is possible, we note that:

- We would expect peaking plant to be reasonably flexible, and measures to implement DS3 System Services will also place greater incentives on plant to increase their flexibility;
- It is appropriate that plant which is inflexible, and which cannot be guaranteed to contribute to system security in a stress event should face greater risk, and should price that risk into its bids, appropriately placing it at a legitimate competitive disadvantage in the CRM auctions relative to more flexible plant, and providing an appropriate exit signal for inflexible plant;
- Depending on the rules on bidding in the energy market, an inflexible plant may be able to partially mitigate this risk by taking commercial measures in the energy markets. For example it could offer a low price into the Day Ahead auction for its min gen volume to ensure it was running. Additionally RO holders could use the IDM to adjust their output to manage exposure to inter-temporal constraints. Whilst the DAM gives rise to a centrally determined schedule, it is participants' responsibility to use the IDM to adjust this schedule for consistency with plant dynamics.

Liquidity and incentives for trading in physical markets

3.3.83 Some respondents have argued that Option 4b distorts relative incentives to trade physical power in the DAM versus the IDM and BM. We have considered this issue, and do not see any material issues associated with the design of Option 4b that would create such undesirable incentives. We can see the following cases worthy of consideration:

- Interaction of Option 4b with scarcity pricing and Euphemia cap; and
- Incentives related to applying one-way CfDs to DAM, IDM and BM

Interaction of Option 4b with scarcity pricing and Euphemia cap

3.3.84 In paragraph 3.3.43 above, we discussed the possibility of generators being incentivised to hold power back from the DAM to the IDM or BM, if the ASP is significantly greater than the Euphemia price cap, and if generators perceive that the probability weighted outcome of the BM or IDM is greater than the Euphemia cap.

3.3.85 However, the design of Option 4b reduces this incentive on RO generators, unlike Option 3. Under Option 3, generators would keep all of benefit of the ASP in the IDM or BM and hence have strong incentive to withhold power. By contrast, under Option 4b, RO generators have to pay back any incentive above the RO Strike Price, which will be lower than the Euphemia cap of €3,000/MWh, removing any incentive to withhold power from the DAM. Therefore in this case Option 4b removes a potential distortion rather than creating one.

Incentives related to applying one-way CfDs to DAM, IDM and BM

3.3.86 By setting reference prices in relation to the market in which each capacity provider trades its energy, Option 4b removes the basis risk between trading in the DAM, IDM and BM, and other things being equal, should leave buyers and sellers relatively indifferent to which market they buy or sell power.

3.3.87 However, due to the properties of option contracts (such as one-way CfDs, which the ROs are a form of), there may be a slight incentive on holders of call options (such as the Reliability Options for Suppliers) to trade in markets with higher volatility.

3.3.88 Consider the case where two markets have the same mean price outcome, but Market A has a higher standard deviation of price outcomes (i.e. volatility) than Market B. In practice, the DAM is likely to have a lower standard deviation of prices than the BM, although in a perfectly competitive market with rational expectations and risk neutral participants, we might expect their means of the two price distribution to be the same.

3.3.89 Now a holder of a call option with a high Strike Price (i.e. a Supplier with an RO) is protected against some of the high price outcomes. Therefore the average cost paid by a Supplier with a call option would be less in Market B than Market A[34]. Provided that the Supplier was perfectly risk neutral, it would prefer to trade in a more volatile market, i.e. the BM[35]. However:

- The incentive on generators would be the opposite, to place offers in the DAM, which is a desirable outcome;
- We would expect any such incentive effects on Suppliers to be small, as the option Strike Price will be set very high, and in practice a Supplier is likely to be averse to the risk of a range of high price BM outcomes well below the RO Strike Price. We would expect a Supplier's choice of market in which to purchase physical power is more likely to be more driven by reference market for two-way CfDs, i.e. the DAM, assuming the DAM is the reference market for two-way I-SEM CfDs. Two-way CfDs protect Suppliers across the whole range of price outcomes, not just a few very high price outcomes;
- We would expect, in an efficient market, if the incentive effect occurred, a small increase in the average DAM price relative to BM price would restore an equilibrium; and
- If such an effect occurred, it is a consequence of the desire to protect Suppliers from extremes of BM prices, in order to protect Supply competition.

[34] Which would be reflected in the option premium

[35] once the call option fee cost is sunk, the option fee would be higher in a more volatile market

Impact on forward financial markets

3.3.90 Some of the respondents also expressed concern about the complexity of the interaction of the RO with existing forward hedging instruments, and the impact on liquidity in forward markets. Some of the respondents were concerned that the choice of Option 4b would exacerbate the complexity and reduce liquidity more than Option 3.

3.3.91 Whilst changes will be needed to the existing two-way CfD contracts to accommodate ROs, the benefits of forward hedging via two-way CfDs can be maintained, including with the adoption of Option 4b. Examples of how Option 4b could be integrated with two-way CfDs are set out in Appendix B.

3.3.92 The SEM Committee note that forward market liquidity in the SEM is much lower than in many other European energy markets, an issue which the RAs may seek to address in the I-SEM, independent of the introduction of Reliability Options. The RAs will consult further on forward market liquidity in the context of the Forwards and Liquidity workstream.

Price based versus scarcity based trigger for RO payout

3.3.93 The consultation paper also discussed whether the RO should payout at any time when the MRP exceeds the Strike Price (a price based trigger), or only when the MRP exceeds the Strike Price *and* administrative scarcity has been declared.

3.3.94 The SEM Committee has decided that the RO should pay out purely price based trigger, not a scarcity based trigger. Therefore if prices rise above the Strike Price for reasons other than scarcity, e.g. the exercise of market power, Suppliers will be protected, and generators will not be able to earn rent for that volume contracted for under an RO.

SEM Committee decision

3.3.95 The SEM Committee has decided to adopt Option 4b: split MRP option.

3.3.96 The RO will payout at any time when the MRP exceeds the Strike Price, regardless of whether administrative scarcity has occurred or not.

Next steps

3.3.97 The SEM Committee also recognises that work needs to be done to determine appropriate arrangements to ensure that capacity providers directed to provide operating reserve or other DS3 System Services are not inappropriately disadvantaged when acting on instruction of the TSO. In this context the RAs will work with the TSOs to develop proposed arrangements and algebra.

3.4 STRIKE PRICE

Consultation summary

3.4.1 The consultation document SEM-15-044 outlined that the Strike Price in the RO is the price at which the TSOs can exercise the call options of all providers of ROs in the I-SEM.

3.4.2 The consultation document set out some of the risks associated with setting the Strike Price too low, namely that:

- There is a risk that some high merit order plant may be exposed to making difference payments at a point when it is still out-of-merit, so will not be earning any compensating energy payments[36].
- As a result, it runs the risk of distorting the energy market. Any generator or demand side unit with an avoided cost[37] which renders it likely to be the marginal price setting bid, will be disincentivised from bidding its true cost.

3.4.3 If, on the other hand, the Strike Price is set too high:

- It does not serve as a control on the exercise of market power by generators; and
- Provides a reduced hedge against price spikes for Suppliers.

3.4.4 The consultation document set out the approach used in other markets with a Reliability Option, such as ISO New England, which is based on a reference Peak Energy Rent unit. The consultation document then asked the following key questions:

- **Should we adopt the "floating" Strike Price approach**, which is indexed to the spot oil or gas price?
- **How do we choose the reference unit**? There are a number of potential approaches that could be considered, including:

- The avoidable (fuel) costs of the **actual** plant on the system that is likely to have the highest such costs.
- A **hypothetical** peaking unit, which may be more fuel efficient than the highest marginal cost plant on the system at the present time. Should a conservative approach be taken to choosing the reference unit and setting the SP, if a hypothetical unit is chosen?

- **Should we grandfather this reference unit** when auctioning long term agreements for new build capacity, or should this reference unit change over time to reflect changes in technology (as the SEM BNE peaking plant does)?

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[36]This risk is a function of the decision to make the RO difference payment purely based on a price trigger, if payments are made based on a scarcity trigger, then all plant will either be providing energy or reserve

[37] Including start up and no-load in the case of a generator, or first hour costs in the case of a DSU

Summary of Responses Received

Floating versus fixed

3.4.5 The majority of respondents favoured the use of a floating Strike Price. Those respondents generally noted that a floating price:

- Gives more certainty that the RO Strike Price will be sufficiently high to prevent interference with the energy market, and would help to achieve the objective that the Strike Price should be set sufficiently high that difference payments are only made when all available capacity is required. If a fixed price is used, it could result in RO holding plant being out of merit, losing energy revenue but still having to pay a difference payment;
- Allows most generation to participate in the RO auctions with some understanding of the relationship of their costs with the RO Strike Price, with an indexed Strike Price that is explicitly linked to a heat rate and a spot input fuel rate insulating capacity providers from risk;

3.4.6 Some of those that favoured a floating Strike Price gave further feedback on the design of the floating Strike Price, in particular, the level at which the Strike Price needs to be set at:

- One of these respondents stated their preference that it is indexed to the spot (within day) gas price rather than the spot oil price.
- Others stated that the floating Strike Price should include allowance for start-up and no load costs, certain transportation costs and other relevant costs due to jurisdictional differences. In particular, one respondent described a scenario with high wind penetration, in which Combined Cycle Generation Turbines (CCGTs) may have to recover start-up and no-load costs over short periods and how the resulting prices could often exceed the fuel cost of a peaking plant. The respondent argued that in the circumstance where the RO is triggered and a CCGT unit has to pay the difference between the market price and a lower Strike Price, it would not be covering its own costs, which is not reasonable or tenable.
- One respondent described how the floating price needs to be set at a level representative of a scarcity event thus ensuring that all RO contracted plant has the opportunity to serve its obligation in such an event.

3.4.7 Some respondents favoured the use of a fixed Strike Price. For these respondents, the main concern was how a variable Strike Price would impact on forward CfDs and risk management, with this concern being more prevalent amongst Suppliers. For example:

- Some respondents in favour of using a fixed Strike Price stated that indexing the Strike Price to fuel prices would create volatility which would be factored into CRM bids;

- One or two respondents were unclear how a floating price RO would dovetail with the futures market to avoid the double hedging problem, whilst others understood how the ROs and CfDs could be integrated but argued that a floating price adds complexity to the forwards contracting arrangements a floating price;
- One respondent argued that use of such an index (e.g. a spot oil / spot gas basket) introduces a basis risk for all generators, and creates a differential risk for generators using different fuel types e.g. coal burning plant. The mixture of an oil and gas index offers only partial mitigation of the risks involved for a gas generator and complicates hedging for both generators and suppliers.
- One respondent described how for generators with low load factors who do not hedge or are unhedged at the time the RO is triggered, a floating Strike Price that is indexed to gas or oil prices could create risk for those generators that erodes the value of the RO, leading them to price a premium in their CRM bids.

3.4.8 Other respondents provided other suggestions:

- One respondent argued that the Strike Price should be tied to a percentage of VoLL;
- One respondent described its preference that the Strike Price should be set for a year for short term RO contracts. For longer term contracts some form of indexing will be required e.g. CPI benchmark as well as or instead of just the commodity price.

Hypothetical versus actual

3.4.9 Just over half of respondents favoured using a hypothetical plant as the reference unit. One respondent described how this will ensure that the Strike Price reflects current technology and generating costs available to the market while also incentivising efficient investment.

3.4.10 Amongst those that favoured the use of a hypothetical unit, there was some debate about what hypothetical unit should be chosen. Points made include:

- A number of respondents discussed the issue of how the Strike Price should be set based on a reference unit with costs significantly higher than the existing marginal plant (use a conservative heat rate).
- That the value used to set the Strike Price should include all marginal costs of generation (including start costs).
- The hypothetical unit should not be the same best new entrant (BNE) as currently used for the SEM capacity mechanism. The BNE in the existing CPM is the new capacity with the lowest fixed cost, whereas in the I-SEM CRM what is required is a proxy for the most expensive variable cost of generation. These are unlikely to be the same.
- A number of respondents coming from the perspective of demand side stated they supported indexing the Strike Price to the SRMC of the marginal capacity

provider which is also the holder of the RO, which could be a DSU. One respondent stated that the Strike Price be set well above the SRMCs of any current DSU.

3.4.11 Other respondents argued that using a hypothetical BNE reference plant would be preferable as would help to reinforce efficient exit signals. Additionally the electricity market is familiar with the BNE approach (continuity with the existing approach) and will provide an adequate framework without added further complexity to the process.

3.4.12 Some respondents favoured using an actual plant as the reference unit. One reason given for favouring an actual reference plant is that it would reduce the scope for regulatory uncertainty. Another respondent described how if the hypothetical reference plant cost is higher than any plant on the system, the RO hedge will not be as effective a hedge for Suppliers. Meanwhile if the cost of the hypothetical reference plant is lower than some plant on the system, it may interfere with the operation of the energy market, and may reduce the number of interested participants in the auction.

Grandfathering

3.4.13 A slim majority of respondents expressed a preference for grandfathering. Support for grandfathering was strong amongst representatives of potential new investors.

3.4.14 These respondents argued that:

- Although it adds some complexity it provides investor certainty for new entrants. However, one respondent noted that investors had borne the analogous risk of changes in the BNE in the current SEM.
- To not offer this would negate the benefit of a multi-year contract as the certainty of revenue is reduced and there is additional risk introduced. Respondents described how if the reference unit is not grandfathered it would cause risk premiums being built into new entrant bids given the uncertainty over the life of the contract.

3.4.15 One respondent suggested that it would be preferable if plant had the option to make small step reductions in its contracted capacity as the years progressed, if it wished to do so. Another respondent argued that a precedent has already been set in SEM where the BNE remains constant for 3 years. They argued that to ensure investor certainty and stability provision could be included in multi-year contracts that the production costs of the new BNE cannot be lower than the initial BNE selected.

3.4.16 A number of respondents did not favour grandfathering the reference unit. Respondents stated grandfathering would be administratively burdensome. Key points made included:

- These respondents argued that grandfathering could create difficulties for the operation of the forward contract market making it impossible for the forward

- market to provide a fully contiguous hedge and mean there is a residual exposure left for some parties.
- One respondent stated that an annual re-basing approach would promote the development of a simpler capacity market operationally-speaking, avoiding the situation of having a number of long term contracts all with different Strike Prices. Another respondent stated that it created challenges for Supplier hedging.

3.4.17 A number of respondents stated that the reference unit should change over time to reflect changes in technology and reflect prevailing forward fuel prices, FX rates, and CPI to encourage efficient entry. A number of respondents suggested reviewing this periodically (annually or in line with auction period).

SEM Committee Response

Fixed versus floating

3.4.18 The SEM Committee is of the view that a floating price best promotes the key I-SEM objectives of system security, efficiency and competition.

3.4.19 A floating Strike Price, if set with reference to an appropriately high variable cost plant, will ensure that the RO does not interfere with the energy market. By ensuring that the Strike Price adjusts naturally to the fluctuations of fuel prices, it will ensure that that the Strike Price does not fall below the marginal cost of plant, and ensure that all plant has an incentive to run and alleviate scarcity. Therefore the floating price promotes system security and efficient dispatch.

3.4.20 It can also promote competition objectives in the:

- Wholesale market: Limiting the incentive for generators to exert market power above the cost of marginal generation; and
- Retail market: Ensuring that Suppliers are afforded the maximum hedge, consistent with not interfering with the energy market, and hence promoting supply competition objectives.

3.4.21 With a fixed Strike Price, either the Strike Price is set at a:

- High level, to ensure it does not interfere with the energy market. In this case, it will not provide Suppliers with a good hedge, and may allow generators to exploit market power when fuel prices are low; or
- Low level, on which case it may interfere with the energy market and disincentivise high marginal cost generators to be available at times of scarcity.

3.4.22 Some respondents have expressed concerns that a floating Strike Price:

- Is more complex. However, the floating Strike Price option is merely an example of an index price trade, which market participants in most electricity and gas markets commonly trade and hedge; and
- Would make it more difficult for Suppliers to hedge appropriately. However, these concerns can be alleviated if the two-way CfDs are adapted to include the same floating price formula, when calculating the ceiling above which to disapply the two-way CfD. An example of how this could work is included in Appendix B.

Hypothetical versus actual

3.4.23 Choosing a hypothetical reference unit will allow the SEM Committee to achieve an optimal trade-off between system security and competition as discussed above. The advantages to using a hypothetical plant include:

- If the highest marginal cost plant that is on the system at any given time is used, this marginal plant may have limited incentives to make itself available. If the formula accurately tracks the marginal cost of the plant, by definition it will make zero net profit by running. We note however, it would be possible to include a tolerance margin of (e.g. 10-20%) above the benchmark of the highest cost actual plant[38]. Also, to the extent that administrative scarcity pricing occurs before load shedding, and causes the price to rise above marginal costs as operating reserve is reduced, the ASP can provides even the high cost marginal plant with the incentive to run.
- It is possible to reflect high cost peaking plant of hypothetical small back-up generators, not currently exporting to the transmission or distribution grids. We note that the use of a heat rate[39] for the Peak Energy Reference plant in New England is less efficient than that which would expected from any system connected licensed generator, at around 15.5% thermal efficiency. This thermal efficiency is much lower than the reference peaking unit currently used for the SEM BNE, the Alstom GT13E2, which has a thermal efficiency of around 35.25%

[38] For instance, Vazquez, Batlle, Riviere and Perez- Arriaga state, "Accordingly, the strike price should be set at least at the level of the marginal variable cost the regulator estimates as the most expensive in the system (as stated above, the regulator may wish to preclude some generators from participating in the auction). Additionally, to avoid any negative impact that an under-estimation of this value could have, the Strike Price could be 10-15% above this value". See Security of Supply in the Dutch electricity market: the role of reliability options, Instituto de Investigacion Tecnologica (IIT), Universidad Pontifica Comilla, Madrid for the Office of Energy Regulation of The Netherlands, December 2003

[39] Efficiencies in the US are typically expressed as a heat rate in BTUs/KWh, where a BTU is a British Thermal Unit = 100,000 therms. A heat rate is the inverse of the thermal efficiency, the way that efficiencies are quoted in Ireland and the UK (albeit in different units, in Ireland and the UK values are expressed as a % of energy content out to energy content in)

when running on distillate and around 37.5% when running on natural gas[40]. In this regard, we would also note that much of the new capacity that was brought forward in the GB 2014 capacity auction were small units - there were 77 new generating units totalling 2,620MW awarded contracts. Excluding Trafford Power Station, there were 74 new units totalling just under 1,000MW, i.e. these units had an average size of less than 15MW, and there were a number of generating units with capacities in the range 2-3MW.

- It would be possible to adjust the thermal efficiency of the hypothetical plant downwards to include an allowance for start-up and other inter-temporal costs.

3.4.24 We note that the hypothetical plant approach also ensures that generators cannot game the regime by installing a small very inefficient high marginal cost generator, specifically with the intention of driving up the Strike Price and reducing the amount that it has to pay out on RO difference payments on the rest of its portfolio.

3.4.25 Some respondents pointed out that an advantage of using an actual plant is that it takes away some regulatory risk, as the reference plant would no longer be a regulatory determined parameter. However, the SEM Committee notes that investors have been comfortable with the idea that the reference BNE plant used to set the SEM Annual Capacity Payment Sum is currently determined.

Grandfathering

3.4.26 The key issue with grandfathering of Strike Prices is how to treat plant with multi-year contracts. The SEM Committee will consult in CRM Consultation 2 on the length of RO contract to be available to existing capacity and new investors in the second CRM consultation, but by way of reference investors in other comparator markets are able to fix their contracts for up to 15 years

3.4.27 Grandfathering RO Strike Prices will create problems for standard two-way CfDs and detract from liquidity in the two-way CfD market, if the hypothetical reference plant is changed from time to time.

3.4.28 By way of example, suppose that the reference unit was grandfathered for new investors with [15] year contracts but changed in line with technology from 15.5% in the 2017 auction, to 16% in 2018 auction 16.5% in the 2019 and so on. Suppose that the 2019 auction related to deliver of new capacity in 2023. Now in the delivery year 2023 there would be 2017 auction winners operating with a Strike Price based on

[40] Note these values are Lower Heating Value (LHV) efficiencies, where as fuel price are typically quoted in Higher Heating Value terms. There is approximately a 10.5% difference for gas and 6-8% for oil (depending on the exact composition of each), which means that an LHV heating efficiency of 37.5% equates to a HHV of 37.5% x (100% - 10.5%) = 33.56%, which is then comparable with the basis on which the NBP gas price is typically quoted.

15.5% x oil price[41], 2018 auction winners operating with a Strike Price of 16% x oil price and 2019 auction winners operating with a Strike Price of 16.5% x oil price.

3.4.29 The 2017 auction winners will want to sell two-way CfDs that do not apply above an oil price x 15.5%, the 2018 auction winners will want to sell two-way CfDs that disapply above 16% x the oil price and so on. This would lead to:

- A range of CfDs for the same delivery period which have different disapplication terms, fragmenting liquidity[42] and making it difficult for generators and Suppliers to track their price exposure;
- Basis risk for Suppliers and capacity providers. For instance, suppose that a Supplier has traded a two-way CfDs with a generator that sells a two-way CfD with disapplication at 15.5% x the oil price, and the Supplier ends up buying in the BM at the ASP. Suppose further that the only generator which had sold in the BM has a Strike Price of 20% x oil price, then the Supplier has a gap in its hedge[43].

3.4.30 Therefore introduction of multiple simultaneous RO Strike Prices would add significant complexity to the two-way CfD market, and probably serve to undermine liquidity in forward markets. **This would materially affect the complexity of hedging and liquidity in the forward wholesale market, potentially damaging competition objectives and creating complexity.**

3.4.31 The SEM Committee recognises that grandfathering the Strike Price may serve to reduce the risk on new investment. However, the SEM Committee thinks that provided the principles for the setting of the reference unit will be easily understood, and that this risk to investors is a small component of the overall investment risk.

3.4.32 For this reason, the SEM Committee believes that the disadvantages of grandfathering outweigh the benefits.

Treatment of start up cost

3.4.33 The SEM Committee recognises that peaking units will have a start-up cost and certain other inter-temporal costs. If the Strike Price formula does not include an allowance for these costs, they may:

- Be disincentivised to run at times of scarcity; and/or

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[41] Or gas price

[42] For instance if you sell a two-way CfD with a disapplication at 15.5% c oil price and sell one at 16% x oil price, you will not have a net zero position, but a small residual exposure between 15.5% and 16% of the oil price. Therefore a trader that has sold a two way CfD with a 15.5% x oil price disapplication will only want to buy a two-way CfD with the same disapplication

[43] In principle it would be possible to treat this as part of the hole in the hedge, and to socialise this gap in the hedge. However, this creates difficulties in matching two-way CfDs to RO volumes, and may create inappropriate incentives for Suppliers

- Be disincentivised from bidding in the RO auctions or incentivised to bid in a significant risk premium.

3.4.34 Consider the case where the RO Strike Price is €500/MWh and a 1MW generator has a short run variable cost of €450/MWh and a cost of €100. If this generator is the marginal unit which is only required for 1 hour, it will cost it €550 to start up and run for 1 hour to honour a 1MW RO obligation[44]. However, the most that it can recover from the energy market is €500. If it bids higher than €500, then it may earn more in the energy market, but this extra revenue is offset by higher RO difference payments, still leaving the generator with a loss. ASP will not help this generator either, as the higher ASP based earnings from the energy market will also be offset by higher difference payments. In this example, this generator may bid for an RO, expecting that most of the time the scarcity event will last at least two hours (the length of time it takes for it to break even in this example), but may choose not to run when scarcity periods are shorter than two hours, and build in a risk premium to cover it for expected losses when scarcity periods are shorter.

3.4.35 One alternative would be for the Strike Price to be set at a higher level to allow the reference unit to recover start up costs even for a short period of running.

3.4.36 In practice, for peaking units, which can start-up quickly and provide capacity at relatively short notice, these start-up costs should be limited. An allowance for the costs could, in principle, be reflected in the choice of relevant thermal efficiency.

3.4.37 The SEM Committee has not decided precisely how start-up costs and other inter-temporal costs should be reflected in the Strike Price formula. We will consult further on the choice of hypothetical reference unit, and how start-up costs should be reflected in the formula in a future consultation.

Treatment of DSUs

3.4.38 The SEM Committee agrees that it is important to facilitate the participation of DSU units (both back-up generation and reduced consumption) in the CRM mechanism. Whilst the choice of reference unit should also reflect the marginal costs of back-up generators, the costs of reduced large consumer demand may not be directly related to fuel costs (e.g. value of lost production, value of stocks in freezers).

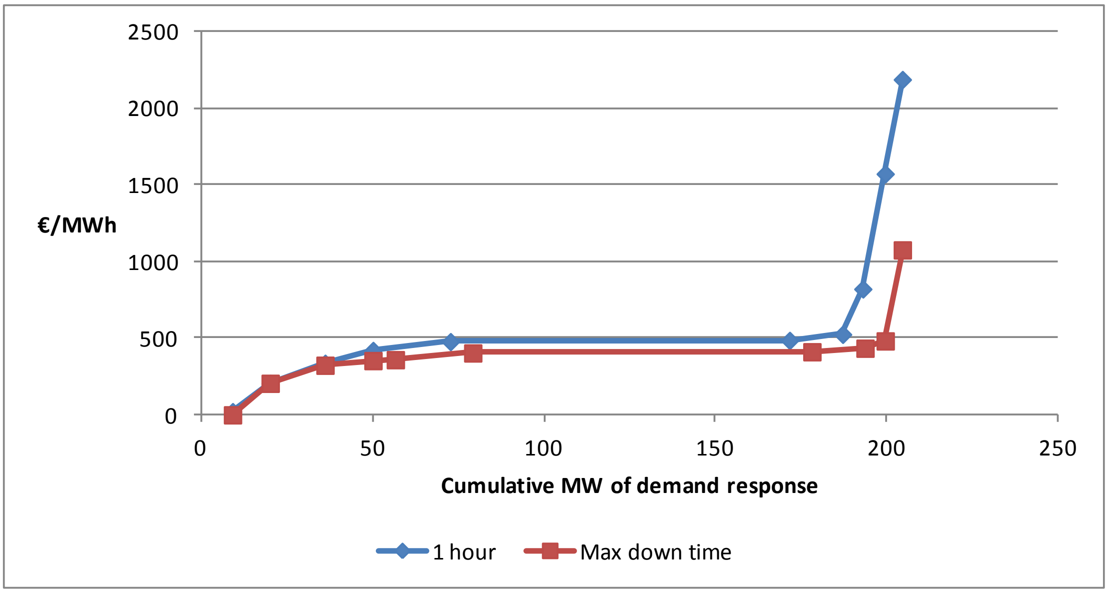
3.4.39 The costs of existing DSUs and the resultant bids (as of 29 August 2015), are shown in **Error! Reference source not found.**. Figure 11 shows the cumulative bid costs arranged in "merit-order", expressed in €/MWh of DSU when running at maximum response (MaxGen) for 1 hour[45], and when running at their maximum downtime. The figure shows that around 190MW of the 205 MW of demand response offered could

[44] For simplicity, in this example, we have assumed that this generator has an RO for 100% of its nameplate capacity

[45] i.e. which results in shutdown recovered over a single hour

be dispatched at €526/MWh or less over 1 hour, and 200MW can be dispatched at less than €500/MWh when dispatched for their maximum downtime[46].

Figure 11: Cumulative cost of DSUs: Cost per MW of running to Max Gen



3.4.40 By contrast, the RAs have calculated that the short run marginal cost of a 15% thermal efficiency plant in Ireland (using the 15% ISO New England benchmark) running off Gasoil, will be in the order of €330/MWh[47] as of the end of August 2015. Therefore it may be appropriate to include a fixed floor price element in the formula, which captures the cost of most DSUs, set at just over €500/MWh.

3.4.41 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 generator market power and providing a hedge to Supplier price risk, which would favour a lower floor.

3.4.42 Therefore whilst the aim need not necessarily be to capture every last MW of demand response of the most expensive demand response operating over a very short period, it is appropriate to capture reasonably cost effective demand side response.

SEM Committee Decision

3.4.43 The SEM Committee therefore proposes to base the RO on a Strike Price reflecting the cost of a hypothetical low efficiency peaking unit, as per the example in New England,

[46] Which for most existing DSUs is typically around 2 hours

[47] Fuel marginal cost only, excluding start-up costs or variable operation and maintenance costs

but also to include an element of the formula which reflects any non-fuel costs related element of DSU costs to be included.

3.4.44 Therefore the formula would be of the form:

Strike Price = Max [1/T% x Max [GRP, ORP], DSU]

Where:

T% is the reference thermal efficiency for the hypothetical Peak Energy Rent unit

GRP is the gas reference price, which will be consulted on further, but which is likely to be a gas spot reference price (e.g. an NBP spot reference price plus a transport adder)[48]

ORP is the oil reference price, which will be consulted on further, but which is likely to be a gas oil spot reference price (e.g. an ARA gas oil reference price plus a transport adder)[49]

DSU is the cost of a reference demand side unit, €/MWh which reflects the cost incurred by demand side in switching off, which may not be related to the cost of energy

3.4.45 The SEM Committee also notes that it may also be appropriate to adjust this formula to include an element of the carbon price in the formula.

Next steps

3.4.46 The RAs will consult further on :

- The annual process for the choice of hypothetical reference peaker (and hence the value of the T parameter above);
- How much of an adjustment to make to the thermal efficiency to reflect start-up and other relevant inter-temporal costs. This is a value that will be reflected in the value of the parameter T above);
- Whether and how to adapt the formula to include an element of the carbon price, and if so, how;
- The principles and process / governance for choosing the fuel and carbon reference prices.

[48] Converted to the appropriate units

[49] Converted to the appropriate units

3.5 LOAD FOLLOWING

Consultation summary

3.5.1 SEM-15-044 outlined that the MW volume on which difference payments are made need not necessarily equal the total volume of RO contracts awarded at auction. If the obligation to make payments is triggered at a time when the requirement for capacity (e.g. defined as system demand plus capacity required to provide operating reserve) is different to the total volume of ROs sold, then each RO obligation can be scaled down[50] pro-rata to reflect:

(Actual demand – (Capacity provided by plant without an RO commitment + Operating Reserve Requirement)) / Volume of RO sold

3.5.2 Therefore if a period of system stress happens unexpectedly outside peak demand periods (e.g. due to low thermal plant availability combined with low wind), the RO obligation is scaled down by the load following adjustment.

3.5.3 The logic behind the load following adjustment is that, in the absence of load following, capacity providers could end up paying more in difference payments than is required to pay out to Suppliers to cap their exposure at the Strike Price.

3.5.4 The consultation document asked if respondents feel that the I-SEM CRM should contain load following.

Summary of Responses Received

3.5.5 A clear majority of respondents who addressed this issue favoured a load following RO obligation. A number of respondents described how load following avoids difference payment over-compensation to Suppliers and allows capacity providers to manage their RO volume risk more effectively, allowing them to accurately reflect their costs in the capacity auction.

3.5.6 However, a few respondents suggested that the additional money received if the load obligation is not load-following, could be needed to fill the potential shortfall in difference payments, the “hole in the hedge”, which might occur due to the non-participation of wind or due to the TSO under-forecasting demand.

3.5.7 One respondent, who did not agree with load following, argued that as a financial option, the RO volume for each capacity provider should be invariant through the duration of the option.

[50] It is not clear that scaling up should occur, as the generators have delivered their contracted volume, and the key issue is that the SO’s estimate of demand was low

SEM Committee Response

3.5.8 The SEM Committee agrees with the majority of respondents that the RO should be load following. If the RO is load following, suppliers will still be able to get the volume hedge they need, but will not benefit from windfall gains, if scarcity occurs outside peak demand.

3.5.9 Making the RO load following will reduce risk for capacity providers (since the volume is capped, and load following asymmetric) and hence could serve to reduce bid costs. **The net result should be lower cost to customers.**

SEM Committee Decision

3.5.10 The SEM Committee has decided that the RO should be load following.

3.6 ADDITIONAL PERFORMANCE INCENTIVES

Consultation summary

3.6.1 In theory, the basic RO alone provides strong financial incentives to be generating when the options are exercised, since the holder has to pay out the difference between the market price and the option Strike Price. If the RO holder is generating then it can sell its output in the market at or close to the reference price and hence back off its exposure.

3.6.2 The initial design of Capacity Mechanisms based on ROs in the US and in Colombia paid relatively little attention to explicit incentives based on physical performance. They relied solely or predominantly on the incentives contained within the basic RO to incentivise capacity delivery at times of system stress.

3.6.3 Both the US and Colombian markets have subsequently found that various market constraints have prevented the RO difference payments alone delivering physical capacity when needed. As a result, in recent years, they have increasingly moved to introduce further incentives during times of system stress on physical performance to complement the incentives embedded in the basic RO. The reforms are ongoing.

3.6.4 SEM-15-044 discussed the requirement for, and design of additional performance incentives, including:

- The form of additional incentives;
- Scarcity based triggers for performance incentives;
- Caps and floors on incentives;
- Performance incentives for renewables and DSUs;
- Performance incentives during the pre-commissioning phase; and
- Detail of any other considerations respondents feel that we should take account of when determining policy in relation to product design.

Summary of Responses Received

Overall design of incentives and penalties

3.6.5 A majority of respondents who expressed a view did not think that there was a need for additional performance incentives (over and above RO difference payments), with a mix of type of market participants on both sides of the argument. Those respondents who argued against the case for additional performance incentives, emphasised the role of appropriately designed RO difference payments, BM arrangements and scarcity pricing in adequately incentivising performance.

3.6.6 One respondent also argued that an additional performance incentive regime created additional risk hedging considerations.

3.6.7 Another respondent was keen to ensure that incentives applied as well as penalties. They argued that RO contracted plants will have uncontracted de-rated capacity available to contribute in a stress event, and they supported the prospect of over delivery payments for this capacity.

Level of penalty cap

3.6.8 A number of respondents stated that if additional performance incentives are introduced then it is important that caps and floors are also designed as part of the arrangement, to manage investor risk.

3.6.9 However other respondents either disagreed with caps on incentives and penalties, or argued that the caps should not be too tight:

- At least one respondent stated that it would be preferable to avoid the complexity of introducing caps and floors on RO difference payments or performance incentives at all.
- A number of respondents stated that the penalty should be able to exceed the value of annual capacity revenue. The cap on penalties should not result in a "free bet" whereby the worst potential outcome for a generator is that it can participate in the CRM, fail to deliver and end up now worse off than if it had not participated

Treatment of intermittent generation

3.6.10 Some respondents argued that intermittent renewable generators should be exempt from performance incentives. Respondents argued that intermittent renewable technologies cannot manage / control their exposure to the incentives and penalties, as wind and other intermittent output is largely outside the generator's control. They argued it is not appropriate to impose penalties on a capacity provider who had no tangible opportunity to manage their behaviour.

3.6.11 By contrast, other respondents argued the need for caution to ensure that a common performance incentive regime is not geared to the needs of a specific technology and described how if a workable technology-neutral performance incentive regime cannot be developed then separate schemes for different technologies may be required. A number of respondents stated that if additional performance incentives are introduced these should apply equally to all eligible capacity providers, specifying that neither renewables nor DSUs should be exempt.

Penalties and central dispatch

3.6.12 Some respondents argued that performance incentives must take account of central dispatch, and were concerned that dispatch instruction from TSO could leave a generator unable to deliver energy against its RO obligation. One respondent suggested that to minimise such risks, generators that have submitted a "valid offer" to the referenced energy market should be exempt from making payments under the RO, and any performance incentive regime, if they are not scheduled or dispatched during a system stress event, or when the market price is greater than the RO Strike Price.

Performance incentives during the pre-commissioning phase

3.6.13 Some respondents emphasised the need for performance incentives during the pre-commissioning stage, to ensure the contracted capacity is delivered.

SEM Committee Response

Overall design of incentives and penalties

3.6.14 The SEM Committee agrees that the case for additional performance incentives is related to the design of the RO and incentives within the energy market - particularly the BM. **With the introduction of ASP, RO difference payments with a reference price based on Option 4b should be sufficient to incentivise capacity owners to make their capacity available at times of system stress and strongly promote system security**. These design features mean the capacity owner faces the marginal cost of their actions, including the marginal cost of lost load. The introduction of the ASP also ensures that generators and Suppliers outside the CRM face strong incentives to generate and reduce load respectively. As result, there is no need to introduce additional incentives and penalties.

3.6.15 GB has introduced a regime of payments for under and over delivery in its capacity market in conjunction with its ASP in its energy market, but the RO difference payment will fulfil the role of providing the necessary incentives in the I-SEM CRM design. Other markets which have introduced an additional performance incentive regime for capacity providers have either stopped short of introducing full VoLL based scarcity pricing or do not have an RO difference payment obligation.

3.6.16 Note however, that the SEM Committee does not preclude:

- Penalties for failing to meet Implementation Agreement development milestones in developing new capacity;
- Availability testing and the right to apply sanctions, including ultimately, terminating RO contracts for failure of availability tests;

Treatment of intermittent generation

3.6.17 The design of the CRM should:

- Promote security of supply and efficient procurement of capacity by allocating rewards and risks to different capacity providers in relation to their contribution to meeting demand at times of system stress;
- Be technology neutral in as far as possible, but should be consistent with EC Guidelines on State Aid for environmental protection and energy (EEAG), and specifically to guideline (233)(e), "*The measure should give preference to low-carbon generators in case of equivalent technical and economic parameters*".

3.6.18 The proposed approach to de-rating (see Section 4.7) will result in allocating intermittent, DSU and energy storage capacity a de-rating factor (and hence potential RO volume), consistent with their technical and economic contribution to meeting demand at times of system stress. By reducing their maximum RO volume on this basis, the de-rating approach materially reduces the risk for intermittent plant. To the extent that residual risk is placed on intermittent plant, this reflects the risk that they are not able to contribute to meeting demand at times of system stress, and reflects their contribution (or lack of contribution) to promoting system security. To the extent they are not contributing to system security, they should not receive capacity payments. To the extent that they only partially contribute to system security, it is appropriate that incentives to intermittent plant should reflect this partial contribution and intermittent plant should price this risk into their capacity bids. Otherwise, system security could be jeopardised.

3.6.19 In the case of intermittent wind plant, analysis of the wind capacity credit set out in the Eirgrid All-Island Generation Capacity statement 2014-2024, suggests that the capacity credit, and hence de-rating factor for wind, may be of the order of 10%. If a 100MW nameplate wind generator has 10MW of RO, at most it can be required to make a difference payment of 10MW x (ASP – Strike Price). If full ASP is broadly €10,000/MWh and the Strike Price is of the order of €500/MWh, the downside risk is -€95,000 per hour of scarcity. By contrast, if it is producing at full nameplate output at the time of scarcity its net revenue would be €950,000 / hour of scarcity[51]. However, the generator's risk also depends upon the extent to which its output is correlated with periods of scarcity.

3.6.20 The SEM Committee does not agree with those respondents who have argued that intermittent plant should be exempt from risks that arise from weather variability. Whilst they may have limited ability to react to price signals by increasing output, it is appropriate that the risk that they do not contribute at times of system stress are priced into their auction bids.

3.6.21 We note that the operation of the energy market presents intermittent wind generators with very high upside potential, which will be uncapped by the RO, since most of the capacity will be de-rated in the RO auction. The upside will be substantially higher with the advent of ASP, and wind producers will be able to realise a gain which equally is for incremental output that it cannot control.

3.6.22 In summary, the SEM Committee believes it appropriate that intermittent generators should be subject to the same incentives and penalties as other generators, which (notwithstanding the impact of the PSOs) will incentivise intermittent generators to optimally risk adjust their CRM volume bids to reflect the contribution they can make to meeting peak demand.

Treatment of energy limited plant

3.6.23 The SEM Committee recognises that increased adoption of energy storage technologies has the potential to deliver value to I-SEM customers. The SEM Committee will consult further on the setting of technical parameters which will define capacity contribution, e.g. how long must a capacity provider be able to provide that capacity for in order to make a capacity contribution. Once those parameters have been appropriately defined, energy limited plant that meet those parameters should be subject to the same incentives and penalties as other capacity providers.

Treatment of DSUs

3.6.24 In principle, demand side should be subject to the same set of incentives and penalties as other capacity providers. However, we recognise that the distinction needs to be drawn between how the combined effect of the I-SEM ETA and CRM allocate revenues, costs, incentives and penalties between the different demand side agents, namely the end consumer, the Supplier and the Demand Side Unit.

3.6.25 In particular, the structure of incentives and penalties will depend upon whether or not the DSU is credited with the energy value of any demand side response. This issue,

[51] Calculated as 10MW (subject to RO) capped at €500/MWh = €5,000 plus 90MW x €10,000/MWh

along with the question of incentives and penalties for DSUs is discussed further in the paper.

Caps on incentives and penalties

3.6.26 The SEM Committee recognises that an appropriate balance needs to be struck between:

- Incentivising capacity providers to perform under all circumstances (for system security reasons), which would favour uncapped RO difference payments for capacity providers;
- Minimising any shortfall in RO difference payments, which would also favour uncapped RO difference payments;
- Minimising disincentives to sell power in the DAM, if the risk of RO difference payments is capped, the risk of having to buy back forced outages in the IDM or BM is not. This disincentive effect is also minimised if RO difference payments are uncapped; and
- Not exposing capacity providers to excessive risk. Excess risk will either be priced into auction offers (which would add to customer bills) and/or deter investment (which would threaten system security).

3.6.27 If RO difference payments are capped, unreliable generators who are close to hitting the cap face a potential disincentive to sell power forward in the DAM. If they sell the power forward in the DAM prior to scarcity, they risk having to buy back the power to cover a forced outage in the IDM or BM at a higher price which reflects scarcity. This loss, which occurs in the energy market is uncapped. However, if the generator withheld the power from the DAM, and declared itself unavailable it would not suffer a loss in the energy market, but would be subject to a penalty as a result of having to make an RO payment. However, if this RO payment is capped, whereas the energy market payment is not, the generator benefits by gaming the system and withholding the power from the DAM. This undesirable incentive is only a factor when both the risk of scarcity is high, and the likelihood that the generator will hit its “stop-loss” limit is material. It is an argument in favour of placing higher stop-loss limits.

3.6.28 Given the desire not to place excessive risk on capacity providers, it is appropriate to impose limits on the level of RO difference payments which a capacity provider could be exposed to, i.e. set a “stop-loss” limit.

3.6.29 However, it is also necessary to define:

- How the loss is defined / measured; and
- At what level to cap the loss.

Defining the loss

3.6.30 There are two alternative way of defining the loss against which the “stop-loss” limits is measured and the limit is set:

- On all RO difference payments; and
- On “uncovered” difference payments.

3.6.31 Where a capacity provider has received an energy payment by selling its capacity into the energy market, its RO difference payment is covered, and it suffers no loss, it merely has its scarcity rent capped. The RO difference payment it makes on this occasion should not count towards the “stop-loss” limit. However, if the generator’s capacity is unavailable, and as a result it has to pay out a difference payment without having an offsetting energy revenue, it suffers a genuine loss and this RO difference payment should count towards the “stop-loss” limit. This approach is illustrated by the worked example in the text box below.

Consider the example whereby a capacity provider has an annual “stop-loss” limit of €15,000 on an RO volume of 1MW, with the stop-loss loss limit based on “uncovered” difference payments. Lets us assume that the RO Strike Price is €500/MWh. Let us further assume that there are two scarcity events, each of which last 2 hours, and during which the ASP rises to €10,000/MWh. Lets us assume that in the first event, the generator sell its 1MW of capacity into the BM and receives €20,000 for 2MWh of production. It has to pay €19,000 of this €20,000 in RO difference payments, but still ends up with net revenue of €1,000. The €1,000 is more than its operating cost assuming the RO Strike Price was set appropriately, but the generator has been stripped of the scarcity rent that it would otherwise have earned. In this case, the €19,000 of difference payment does not count towards the “stop-loss” limit.

Now let us assume that in the second event, the capacity is on forced outage, and does not sell its output. Now in the absence of a “stop-loss” limit, it would have to pay a RO difference payment of €19,000 on this second event, without having any energy revenue to cover the difference payment. However, the “stop-loss” limit means that it only has to pay out on the “uncovered” difference payments up to a maximum of €15,000. As a result, there is a €4,000 shortfall in RO difference payments (“hole in the hedge”) to be funded out of a socialisation fund.

By contrast, if the stop-loss limit has been based on all difference payments, with a €15,000 “stop-loss” limit, the generator would have paid only €15,000 of difference payments on the first event, and no payments on the second event. The total shortfall in RO difference payments across both events would have been €23,000 instead of €4,000.

3.6.32 The SEM Committee is of the view that “stop-loss” limit should be applied to “uncovered” difference payments because this approach:

- Better reflects the risk placed on capacity providers- where capacity providers sell energy into a market with scarcity pricing, they have an income to offset the risk of accumulating RO difference payments;
- Maximises the extent to which scarcity rents are taken back from generators, one of the features which underpinned the choice of ROs in the I-SEM CRM HLD; and
- Provides a better hedge to Suppliers, and minimises the size of any RO difference payment shortfall that needs to be socialised- another of the features which underpinned the choice of ROs in the I-SEM CRM HLD;

3.6.33 The SEM Committee recognises that this will lead to greater RO difference payments than if the loss was defined based on total difference payments (for a given “stop-loss” cap), and that capacity providers can be expected to price the extra payments into their auction bids. The SEM Committee further recognises that all other things being equal, the cap is more likely to apply to an unreliable generator than a reliable generator, so that a reliable generator can be expected to price higher difference payments into their auction bids- an undesirable outcome. However, on balance the SEM Committee favours applying the cap to uncovered difference payments.

Level of the loss

3.6.34 The SEM Committee received little response on the level of “stop-loss” limit. Therefore the SEM Committee will consult further on the level at which the stop-loss will be set at. However, the SEM Committee thinks that the cap on RO difference payments should be more than the annual capacity fee. The SEM Committee is minded to set an annual ”stop-loss” in the range of between x1 and x2 annual capacity fees.

3.6.35 The SEM Committee also received little response on the structure of “stop-loss” limits and will consult further on whether to set monthly and per event “stop-loss” limits. A cap on monthly fees at X% of the annual ”stop-loss” and/or a per event “stop-loss” limit could prevent single event or a related series of events removing the RO difference payment incentive for the remainder of the year.

Other issues

3.6.36 The SEM Committee agrees that other enforcement action may be necessary for capacity providers who fail to provide capacity (or who fail repeated availability tests), and therefore jeopardise system security.

SEM Committee Decision

3.6.37 The SEM Committee has decided that:

- Case for additional incentives: With the introduction of Administrative Scarcity Pricing at levels around the SEM VoLL and RO difference payments based upon MRP Option 4b, the CRM design will provide strong incentives on capacity providers to perform. **The SEM Committee does not see the need for further performance incentives, over and above ASP and RO difference payments, at this time**.

- Intermittent generation and energy storage. **RO difference payments should apply to intermittent generation and energy limited plant in the same way** as they do to conventional technologies such as gas turbines, oil and coal fired plant.
- Section 4.5.20 outlines the SEM Committee decision regarding the treatment of DSUs.
- It is appropriate to apply caps to uncovered RO difference payments, i.e. RO difference payment minus energy income on relevant capacity.

Next steps

3.6.38 The SEM Committee is of the view that further work needs to be done to determine the level and structure of the cap on RO difference payments. Further work is required to:

- Set the level of the annual “stop-loss” limit. The SEM Committee is minded to set an annual ”stop-loss” in the range of between x1 and x2 annual capacity fees.
- Determine the structure and level of other “stop-loss” limits. The SEM Committee is also minded to set a cap on monthly fees at X% of the annual ”stop-loss”, to prevent single event removing the RO difference payment incentive for the remainder of the year, and may also set a ”stop-loss” on a per event basis. More work is required to determine the level of these “stop-loss” limits.

3.7 MANAGING SUPPLIER RISK

Overview of issue

3.7.1 During the course of consultation presentations and discussions it became apparent that the emerging CRM design could lead to the level of RO difference payments from generators being insufficient to cover the required level of RO difference payments to Suppliers. Any such shortfall would leave Suppliers without a full guarantee that they would be hedged in the reference market above the RO Strike Price.

3.7.2 This issue, which has colloquially become known as the “hole in the hedge”, was first identified in the context of the discussion around whether supported renewables generation would be eligible to compete in the CRM - the implication being that if supported renewables were ineligible, then the volume of ROs to be purchased could be less than peak demand, leaving a shortfall in receipts from capacity providers. Whilst the SEM Committee has decided that supported renewables will be eligible to compete (see Section 4.2), it will not be mandatory for intermittent plant (see Section 4.3) to compete, leaving open the possibility of a shortfall. The RAs have identified a number of other potential causes of a shortfall, resulting from decision made in this document. These are:

- **Intermittent generator opt-out**: As set out in Section 4.3, whilst all intermittent plant may bid into the CRM auction if it chooses, it will not be mandatory for intermittent generators to bid. It may be that intermittent capacity chooses not to bid in the auction, and we will reduce the amount of ROs purchased commensurate with the assumed capacity contribution of the non-bidding plant (to avoid paying for capacity we do not need). Given the likely de-rating of wind, we expect wind to contribute around 7-*8% of de-rated capacity* in the period 2017-2024[52].
- **DSUs:** As discussed in Section 4.5, whilst the SEM Committee continues to investigate the viability of solution whereby DSUs receive energy payments and make RO difference payments, it may be that, at least initially, DSUs will not be required to make RO difference payments when their customers' reduced load, leading to a shortfall. DSUs account for about 200MW of capacity in the SEM, i.e. about *3% of peak demand*.
- **Supplier demand side response**: Where a Supplier buys energy in the DAM or IDM and is subsequently able to sell that energy back into the IDM or BM under scarcity conditions (e.g. because it has provided demand response) the Supplier will not be required to make a difference payment on the volume it has sold back[53]. The level of shortfall therefore depends on the level of Supplier demand response after scarcity ;
- **Capacity provider penalty caps:** As set out in Section we plan to set penalty caps (also called "stop-loss" limits) for capacity providers, which limit their exposure to uncovered difference payments (see Section 3.6). We plan to set this stop-loss level as a multiple of fees[54], and to consult on the multiple in CRM Consultation 2. The size of the potential shortfall is a function, *inter-alia* of the penalty cap level, the frequency and severity of scarcity prices, and the level of RO generator outages. We have done some estimates of the potential loss to suppliers and they are in the *range €0-35m p.a*. to Suppliers if there are 8 hours of lost load in a year, although this may not make full allowance for incidences of scarcity short of lost load.
- **Peak demand under-forecast**: As set out in Section 2.4, the capacity requirement will be set on the basis of the "optimal" scenario. If this scenario

[52] Based upon Eirgrid Capacity Statement, 2015-2024

[53] Since Supplier payments are not capped by the RO this provides a strong incentive for demand response

[54] In consultation 2 we will consider whether caps should be a multiple of annual fees, and/or monthly fees and/or on a per event basis

turns out to be less than the actual peak demand, and scarcity occurs at peak demand, there will be a shortfall. However, we note that:

- In GB the "least worst" scenario selection tends to select a scenario with demand forecasts at the higher end of the range covered by the scenarios;
- The RO volume is set at a level to meet the security standard, which could be mean that de-rated capacity procured may exceed peak demand. Evidence from GB indicates that the total de-rated capacity requirement tends to be higher (between 101% and 106%) of the peak demand for the relevant scenario, although the excess may be different for the I-SEM[55];

3.7.3 Any difference payment shortfall/deficit could also (at least partially) offset by a potential that, at times, there will be a surplus of difference payments in the CRM. That is, the difference payments received through the Reliability Options are greater than those required to fully hedge Suppliers against market prices that are above the RO Strike Price. This surplus is a feature of the fact that difference payments are only paid to Suppliers that buy in the I-SEM markets – with no difference payments paid to Generators that buy back generation to cover their outage[56].

3.7.4 The RAs recognised the potential for any shortfall, and discussed "socialising" (or equivalently, socialising) any shortfall amongst all Suppliers, to protect individual Suppliers against any potential shortfall at the public workshop held in Dundalk on 28th September 2015.

Consultation discussions

3.7.5 During the stakeholder workshop in Dundalk and in bi-lateral meetings following presentations, a number of stakeholders expressed concern about the hole in the hedge issue, particularly in the context of the potential introduction of ASP and of Option 4b for the MRP.

3.7.6 In particular, some stakeholders expressed concern that ASP, coupled with a potential "hole in the hedge" could be a significant risk to Suppliers.

3.7.7 Other stakeholders argued that the "hole in the hedge" was grounds for not opting for Option 4b, under which the "hole in the hedge" is most likely to occur.

3.7.8 Some stakeholders, principally generators or vertically integrated utilities argued that it is inappropriate to socialise any shortfall. The burden of any shortfall falls only on

[55] Relative to GB, the excess will depend on three factors: the relative approach taken by GB and I-SEM authorities in setting de-rating levels; the 8 hour LOLE security standard in the I-SEM compared to 3 hours in GB, which ceteris paribus would lead to a smaller excess in the I-SEM; and the smaller size of the I-SEM system which ceteris paribus would lead to a larger excess in the I-SEM

[56] For example, this surplus could (and is likely) to occur following a generator trip

any Supplier that fails to accurately forecast and procure/hedge[57] its energy before scarcity occurs, and these stakeholders argue that this forms the basis of an appropriate incentive on Suppliers to forecast and procure/hedge their energy requirements at an early stage. By socialising any shortfall, Suppliers who accurately forecast and procure/hedge their energy in advance of scarcity would share the burden of Suppliers who failed to accurately forecast and procure/hedge their demand.

SEM Committee View

3.7.9 The SEM Committee has carefully considered the issue of the risk on Suppliers as a result of the overall CRM design, and on balance, favours socialisation of any shortfall in RO difference payment from capacity providers (the hole in the hedge).

3.7.10 In adopting the I-SEM High Level Design, the SEM Committee saw significant advantages in the fact that ROs offer Suppliers a hedge against market prices spikes. Key pros of ROs and particularly centralised ROs[58] included the facts that:

- ROs provide all Suppliers with a hedge against high prices. By doing so, the ROs better promotes the I-SEM objectives of competition in Supply, and hence indirectly, efficiency objectives;
- Centralised ROs ensure that all Suppliers, and hence by extension all end customers, face the same price for reliability in the I-SEM. As a result, the RO, provided it contains a hedge for all Suppliers better promotes I-SEM equality objectives.

3.7.11 The introduction of ASP is necessary to sharpen incentives on capacity providers to be available at time of system stress, and to provide Suppliers with strong demand response incentives. However, along with other decisions taken in this document, it exacerbates the potential magnitude of the “hole in the hedge”, unless the shortfall is socialised.

3.7.12 The SEM Committee recognises that if there is a shortfall in difference payments which is not socialised, these key objectives of competition in Supply and equality amongst customers are threatened.

3.7.13 In particular, the SEM Committee is concerned about the impact on non-vertically integrated Suppliers, or vertically integrated Suppliers that are net buyers, of any hole in the hedge. As discussed in Section 3.3, a vertically integrated utility is likely to benefit from a “natural hedge”-i.e. there is a significant probability that a price spike which causes losses in its Supply business is offset by increased profit in its Generation

[57] If scarcity has already occurred at Day Ahead stage, a Supplier cannot procure its physical energy at pre-scarcity prices, but it could have forecast the demand in advance and struck a 2-way CfD against the DAM price which gives it the financial hedge against scarcity prices in the physical market.

[58] As opposed to de-centralise ROs where Supplier contract individually at potentially different prices

arm, particularly where the price spike is caused by the ability to earn scarcity rent, not by an increase in variable fuel cost. As further discussed in Section 3.3, the choice of Option 4b serves to limit the exposure of all Suppliers to price spikes, and this protection is most valuable to non-vertically integrated Suppliers without a natural hedge. However, if there is a shortfall, this protection is only partial, and could lead to reduced competition in Supply.

3.7.14 The SEM Committee recognises the point made by certain stakeholders that socialisation of any hole in the hedge blunts the incentive on Suppliers to accurately forecast and procure/hedge their customers' demand in advance scarcity. However, the SEM Committee notes that whilst it blunts the incentive to some degree Suppliers are still:

- Fully exposed to price risk on their forecast errors at all times, except the relatively rare occasions when scarcity drives prices above the RO Strike Price; and
- Even on the infrequent occasions when scarcity applies, Suppliers are still exposed to price risk up to the RO Strike Price.
- As outlined above, forecast errors are not the only source of the "hole in the hedge", and Suppliers remain exposed to these other factors.

3.7.15 Therefore on balance, the SEM Committee has decided that any shortfall in the hedge provided through Reliability Options will be socialised across all suppliers.

3.7.16 The SEM Committee does not agree with stakeholders who have argued that the "hole in the hedge" is a reason not to opt for Option 4b on the MRP. The shortfall is potentially bigger under Option 4b, but only because it provides Suppliers with a better hedge and better promotes the I-SEM objectives than Option 3 or other options.

SEM Committee Decision

3.7.17 The SEM Committee has decided that any shortfall in RO difference will be socialised across all Suppliers.

3.7.18 Socialisation will:

- Be funded by surplus difference payments that arise when difference payments from RO providers exceed those required to hedge Suppliers, as well as by charges to all Suppliers. These charges to Suppliers may be negative (i.e. a rebate) if there are frequent occurrences of surplus difference payments;
- Recover (or pay) those charges from (to) all Suppliers as an adjustment to the price Suppliers are charged to cover the annual cost of Reliability Option Fees;
- Have a "k factor" adjustment to the price Suppliers are charged for a given year "y" to reflect any short-fall or surplus in the previous year "y-1".

3.7.19 The SEM Committee will keep the principle of socialising any shortfall in difference payments under review, and may discontinue this socialisation at later date.

Next steps

3.7.20 In CRM Consultation 3 we will consult on the detailed design of the arrangements for the socialisation of any shortfall in RO difference payment. This will include the approaches to set the charge to Suppliers for socialisation including:

- Estimating the level of any shortfall in difference payments; and
- How any under or over-recovery is treated.

3.8 SUMMARY OF SEM COMMITTEE DECISIONS

Administrative Scarcity Pricing (ASP):

- Administrative Scarcity Pricing will be introduced into the energy imbalance price.
- Scarcity (for the purposes of Administrative Scarcity Pricing) will be defined as when there is insufficient capacity to maintain the target operating reserve.
- A simplified piece-wise linear approximation will be applied to calculate to 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 Paper (SEM-15-064).

Market Reference Price: Adopt Option 4b: split market option.

Strike Price: Strike Price based on a hypothetical low efficiency peaking unit, but also to include an element of the formula which reflects any non-fuel costs related element of DSU costs

Load following: The RO should be load following

Additional incentives and penalties:

- No need for further performance incentives, over and above ASP and RO difference payments, at this time.
- RO difference payments should apply to intermittent generation and energy limited plant in the same way as they do to conventional technologies such as gas turbines, oil and coal fired plant.
- Apply caps to uncovered RO difference payments, i.e. RO difference payment minus energy income on relevant capacity.

Managing supplier risk: Any shortfall in difference payments receipts from capacity providers will be socialised across the generality of Suppliers.

4. ELIGIBILITY

4.1 INTRODUCTION

4.1.1 SEM-15-044 described how the Eligibility criteria will be used to determine whether a capacity provider is eligible to provide the physical backing for a Reliability Option, and how many MW of RO can be backed by a given MW of "nameplate" capacity.

4.1.2 In SEM-15-044, the SEM Committee consulted upon the following aspects of eligibility:

- Supported generation and renewables not receiving support;
- Mandatory vs. discretionary bidding and adjustment of capacity requirement;
- Treatment of generation with non-firm transmission access;
- Demand Side Participation;
- Other potential capacity sources and energy limited plant;
- De-rating;
- Treatment of aggregators and PPA providers; and
- Qualification.

4.2 SUPPORTED GENERATION AND RENEWABLES NOT RECEIVING SUPPORT

Consultation summary

4.2.1 Some capacity providers on the island of Ireland may be able to recover some or all of their capacity costs through specific support mechanisms, including:

- 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; and
- Longer term DS3 System Service support contracts.

4.2.2 SEM-15-044 consulted on whether generation capacity which is compensated under such support mechanisms should be eligible to participate in the I-SEM CRM. SEM-15-044 stated that:

- It is desirable from an economic efficiency perspective to allow different technologies to compete on an equal basis to provide capacity in the I-SEM CRM;
- This principle is enshrined in the EC Guidelines on State Aid for environmental protection and energy (EEAG) that relate to capacity mechanisms, which states as a general principle that all types of capacity that meet physical checking and performance requirements should be eligible;

- The EEAG also requires preference to be given to lower carbon capacity providers in the case of equivalent technical and economic parameters and require that demand side and storage operators are eligible to participate.

4.2.3 However, SEM-15-044 also noted that the EEAG also recognise that it may be appropriate to limit participation in capacity mechanisms where this is necessary to prevent overcompensation, for example because there is a separate aid scheme for a particular class of capacity provider.

4.2.4 SEM-15-044 further noted that:

- Supported generation has been able to receive capacity payments in the SEM;
- The UK government has taken the view in GB, that where low carbon generators have ROCs or FiT CfDs, the generator should be precluded from receiving capacity payments and preference for low carbon generation was given through the carbon price floor[59].

4.2.5 SEM-15-044 then set out a number of options for the treatment of supported generation, and a preliminary analysis of these options, and asked for feedback on the options. The options were:

- Option 1: All supported generators ineligible as in GB;
- Option 2: All existing supported generators who have been eligible for SEM capacity payments are eligible, but future generators will be ineligible.
- Option 3: All supported generators eligible.
- Option 4: Scheme by scheme specific treatment.

4.2.6 SEM-15-044 also stated that the inclusion of unsupported renewable plant, including intermittent renewable plant, would appear to be consistent with EU State Aid guidelines.

Summary of Responses Received

4.2.7 The majority of respondents strongly supported Option 3 - that all supported generators should be eligible to participate in CRM. A number of respondents stated that the CRM should be eligible to all with no special treatment, exclusions or preferential terms, and providing their level of participation reflects the contribution the capacity makes to providing security of supply to customers.

4.2.8 A number of respondents favoured supported renewable plant being eligible to participate to the extent that they are not over remunerated and provided that they take on additional financial risk to physically deliver power during periods of scarcity.

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[59] In the EEAG requirement to give preference for low carbon generation in GB was demonstrated through the UK carbon price floor where low carbon generation would be able to bid more competitively in the capacity auction by virtue of the carbon price floor. There is no equivalent of the carbon price floor in Ireland and it does not apply to Northern Ireland generation.

Some respondents argued that from the perspective of REFIT projects, participation could be viewed as cost neutral given that the PSO will top up the generator in the absence of capacity payments in any case, with consumers paying for both the PSO and the RO. One respondent noting this point favoured the view that supported plant (REFIT or other supports) should not be permitted to avail of capacity payments, noting any capacity payments made to supported generators under REFIT scheme should reduce the amount payable under the PSO levy but for transparency this payment should be made via PSO levy.

4.2.9 Some respondents pointed out that under the NI ROC support mechanism in Northern Ireland supported plant receives capacity payments in addition to the energy payments and renewable obligation payments with capacity payments being an additional revenue stream. It was argued any change to this would amount to a retrospective change which would erode revenue streams that supported original investment decisions.

4.2.10 One respondent described the difference between the I-SEM and GB market in that GB plants in receipt of renewable subsidies were not considered eligible for the capacity mechanism in GB, but argued that the existence of a carbon price floor in GB maintained a strong renewables market enabler.

4.2.11 One respondent described the difficulty in determining eligibility where only part of the output is renewable (such as in waste to energy facility). This renewable portion could be variable due to the nature of the fuel composition (e.g. municipal waste). This is calculated ex-post for annual REFIT submissions, but if this renewables contribution was ineligible for ROs, it would be difficult to calculate the available non-renewable RO capacity, creating an administrative challenge.

SEM Committee Response

4.2.12 The SEM Committee agrees that, on balance, all supported generation should be eligible to participate in the CRM.

4.2.13 The key arguments in favour of allowing supported generation to participate in the CRM are:

- Allowing all supported generation **maximises competition in the CRM.** The total nameplate capacity affected includes of 380MW peat generation in Ireland, 595MW of legacy GUA generation in Northern Ireland and a projected all-island installed wind capacity of over 4,000MW by 2017. The wind capacity has a relatively fragmented ownership, which is also good for competition. Whilst wind capacity will contribute much less capacity on a de-rated basis, these plant can still contribute substantially to CRM competition;
- It is **equitable** that the CRM should support participation by all technologies and should reward all market participants in relation to their capability to provide capacity;

- By allowing supported generation to participate we increase the coverage of the RO hedge for Suppliers, and **reduce the requirement for socialisation of any shortfall in RO difference payments**;
- Allowing supported generation to obtain capacity payments in the I-SEM, as they have done in the SEM will enhance **stability** and keep perceptions of regulatory risk low.
- The approach of allowing all supported generation to compete is clearly **consistent with EEAG guidelines** which requires preference to be given to lower carbon capacity providers in case of equivalent technical and economic parameters

4.2.14 The SEM Committee considered the key counter-argument that allowing supported generation to participate could lead to over-compensation of certain generators, and increase cost to customers.

4.2.15 The RAs have carried out further analysis and found that the inclusion of supported generation is likely to have net zero effect on customer bills with the exception of existing Northern Ireland Renewable Obligation Certificate (ROC) supported generation.

4.2.16 There are a range of support schemes in Ireland and Northern Ireland, and the withdrawal of capacity payments from supported generators (who are eligible to receive SEM capacity payments) would have different potential effects depending on the support scheme in question. In practice, for most support schemes, such as the REFIT schemes for renewables[60] and PSO support for peat in Ireland, the legacy GUA contracts and the future FiT CfDs[61] in Northern Ireland, allowing supported generation to obtain I-SEM capacity payments will lead to a commensurate reduction in payments via the support schemes (or greater rebates to customers in the case of Northern Irish GUA plant) with a neutral overall effect on customer bills across the island of Ireland[62].

4.2.17 The key exception to this is Northern Ireland ROC scheme, which provides support to most existing Northern Ireland renewable generators. ROCs are an addition to the market revenue earned by ROC generators, and the ROC scheme would not compensate ROC generators for loss of capacity payment revenue.

4.2.18 The RAs have estimated the likely level of capacity payments to Northern Ireland ROC generators, and found that:

[60] With REFIT schemes, if market revenues exceed the support level then additional capacity payments will be retained by the generator- customers are only rebated when the overall revenue is below the support level. However, to date and at current price levels, additional capacity payments would be reduced by reduction in payments from the REFIT support mechanism.

[61] Whilst the market reference price for Northern Ireland FiT CfDs has not been defined, it is likely to include an element for capacity payments

[62] Although capacity payments are recovered from customers across the island, whereas top-up support from Public Service Obligation funds are recovered on a Ireland/Northern Ireland specific basis.

- The level of support for NI ROC generation is likely to be in the range £2-£6m p.a.[63]
- The level of capacity payment is likely to be less than under the SEM CRM, which will reduce customer bills.

4.2.19 Therefore on balance, the SEM Committee has decided that it is appropriate to allow all supported generators to participate in the I-SEM CRM[64].

4.2.20 As discuss in Section 4.3 below, whilst all supported generators will be eligible to participate, it will not be mandatory for intermittent supported generators to bid.

SEM Committee Decision

4.2.21 The SEM Committee has decided in favour of **Option 3: All supported generators eligible**, subject to the same de-rating principles as will be applied to other capacity providers.

4.2.22 All **unsupported** renewables will also be eligible to participate in the CRM, subject to the same rules as other capacity providers.

4.3 MANDATORY VS DISCRETIONARY BIDDING AND ADJUSTMENT OF CAPACITY REQUIREMENT

Consultation summary

4.3.1 SEM-15-044 stated that the SEM Committee may choose to make it mandatory for eligible generators to bid into the CRM auctions, in order to prevent abuse of potential market power. A particular concern would be that a portfolio generator could withdraw capacity from the auction in order to drive up the market clearing price, and earn a higher capacity payment on the rest of its generation portfolio. This requirement to bid would apply only to existing generators, not potential new investors.

4.3.2 SEM-15-044 noted that there are other ways to address these potential gaming issues. For instance, the capacity procurer could adjust down the amount of capacity bought if a generator which was expected to contribute capacity chose not to bid. The

[63] The level of support depends upon the assumed wind derating factor (we have assumed 10%), the assumed NI wind generation installed capacity (we have assumed an increase from the 2015 installed capacity of 612MW in 2015 to 814MW by 2017) and the assumed auction clearing price. We have assumed a range of auction clearing prices from €24/kWp.a. (the GB 2014 auction outcome) to €80.2/kW p.a. (the 2015 SEM Best New Entrant price)

[64] However, for the avoidance of doubt, the SEM Committee does not agree that any commitment has been given to Northern Ireland ROC generators, or that they have a legitimate expectation that they will always continue to receive capacity payments

consultation document noted that adjusting the capacity requirement would address some market power concerns (the balance between volume bid and volume purchased) but not all market power concerns (a potential reduction in the number of bidding companies).

4.3.3 It was also noted in discussions at subsequent public workshops that allowing generators to no-bid would potentially increase the size of the “hole in the hedge” issue (see discussion in Section 3.7).

4.3.4 Consultees were invited to set out their views on whether it is appropriate to make it mandatory for generators to bid, or whether it should be discretionary, in the light of market power concerns and other concerns and the range of other remedies available.

Summary of Responses Received

4.3.5 There was a mix of responses both in favour of and against mandatory bidding. Those respondents that favoured mandatory bidding, did so citing concerns with regard to the potential for the exercise of market power and market manipulation. These respondents described how mandatory participation would prevent unilateral discretion as to what capacity would be bid in by providers removing any opportunity to potentially game their respective portfolios.

4.3.6 Some of those respondents who favoured mandatory bidding also argued that there needs to be a clear mechanism to deal with plant opting out of the CRM, both in terms of adjusting the capacity requirement and also ensuring that opted out plant delivers on its stated intention (be it to close or stay online).

4.3.7 Some respondents did not favour mandatory participation in the I-SEM. This was particularly the case for representatives of intermittent renewables, who argued that variable sources like wind are particularly exposed to risk, which they cannot control. One of these respondents made the distinction of supporting mandatory qualification but not mandatory participation, with mandatory qualification ensuring the TSO has an accurate picture of the system when it holds the auction.

4.3.8 One respondent argued that enforced mandatory bidding would be seen as increasing regulatory risk to doing business in Ireland. Another respondent stated that bidding should not be mandatory if penalties are potentially greater than annual CRM revenues.

SEM Committee Response

4.3.9 The SEM Committee has evaluated whether it should be mandatory to participate in the CRM, or at the capacity provider’s discretion. A capacity provider’s discretion may include:

- The discretion whether to bid at all in the auction; and
- If they bid, whether to bid all of their de-rated capacity into the auction, or whether they are allowed to bid less than their de-rated capacity[65].

4.3.10 In making its decision, the SEM Committee needs to balance the following:

- **Competition and market power concerns**- which are best alleviated by making it mandatory for all generators to bid their full de-rated capacity;
- **Risk to generators**, particularly intermittent generators. If unmanageable risk is imposed on generators, the risk will be priced into auction bids to the detriment of customer bills. Risk to generators is lowest if they have complete discretion to no-bid;
- The efficiency of the Supplier hedge and level of socialisation of any shortfall.

4.3.11 These are discussed in turn below, with the exception of the Supplier hedge, which is discussed in Section 3.7.

4.3.12 In addition, if generators have any degree of discretion over the MW value of their bid, a process will need to be established which gives the TSOs the information required to allow them to adjust the capacity requirement.

Competition and market power concerns

4.3.13 The main reason to consider making participation mandatory is to mitigate market power. In particular, we are concerned that a portfolio generator may seek to game the market by withholding some of its capacity from the auction, with a view to increasing the market clearing price and earning greater revenue on the residual capacity it bids into the auction.

4.3.14 However, there are non-gaming related reasons why a capacity provider may wish to bid less than its de-rated capacity, e.g. it genuinely believes that its plant cannot deliver to a centrally determined standard or because it is risk averse and does not want to expose itself to the risk of not being available when the RO is called[66].

4.3.15 One way of partially addressing market power concerns is to adjust the amount of capacity procured by subtracting any capacity which will remain on the system for the delivery year in question, but which opts not to bid into the auction. This addresses one source of concern with regard to market power (that withdrawal of some providers could lead to a reduction in capacity bid over capacity required) but not the concern that withdrawal of some players will lead to a highly concentrated market with only a few large players.

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[65] For instance if they have a 400MW nameplate CCGT, and it is determined that CCGTs should be de-rated to 90% of their nameplate capacity, does the generator have to bid 360MW into the auction, or can it bid anywhere between 0 and 360MW into the auction?

[66] The risk depends on how we choose to cap difference payments

Risk to generators, particularly intermittent

4.3.16 A number of respondents have expressed concerns that generators will be exposed to the risk that they are unable to deliver their RO capacity at times of scarcity and that they will have to make RO difference payments without offsetting energy market revenue. This point has been emphasised most by representatives of wind generators, who also point out that their exposure is to large extent, linked to wind strength, which they cannot manage[67].

4.3.17 The overall CRM design provides generators with a degree of mitigation of this risk, including:

- De-rating: the de-rating factors will reflect the probability that different technology types will be able to generate at times of systems stress, including, for instance the correlation of wind output with likely system stress. Therefore to some extent mitigation of this risk is built into the de-rating approach; and
- "Stop-loss" limits: as discussed in Section 3.6, caps will apply to uncovered difference payments, which will mitigate the risk to generators.

4.3.18 However, generators who participate in the CRM will retain a degree of risk exposure- and rightly so, since this risk is part of the incentive to deliver.

4.3.19 The SEM Committee recognises that the risk exposure faced by intermittent plant is different from that faced by dispatchable plant, in that output is more variable and less within the control of the generator.

4.3.20 Some respondents have argued that dispatchable generators face risk which is outside their control, namely that they are available but are not dispatched because the I-SEM is not a self-dispatched market. The SEM Committee does not agree that generators will face material risks which are outside their control, and notes that as discussed in Section 3.3:

- At times of system scarcity, when ROs will be called, most if not all generation will be required;
- Generators can manage this risk by trading in the IDM to ensure they are dispatched against a deliverable profile and are in position to deliver their RO commitment; and
- It is appropriate that more inflexible plant should face this risk and price it into their auction bids.

[67] There may be ways of managing this risk, such as investing in an aggregated portfolios which includes batteries, but this requires significant investment, and there may be issue associated with the requirement to separately meter wind and battery output.

Further SEM Committee Consideration

4.3.21 The SEM Committee considered a number of options for obligations on existing generators to participate in CRM auctions, with increasing degrees of mandation:

- Option 1: Nothing is Mandatory;
- Option 2: It is mandatory for all existing generators to submit qualification information saying how many MW they are going to bid (which would allow the TSOs to adjust the capacity requirement), but all generators have complete freedom to no-bid (or to bid only a portion of their de-rated capacity);
- Option 3: It is mandatory for all existing generators to submit qualification information as above. Generators have to bid within a minimum and maximum tolerance range. Such a tolerance range would be tight, no greater than to encompass the genuine range in the technical characteristics of plant within that technology;
- Option 4: It is mandatory for all existing generators to submit qualification information as above. It is mandatory for all existing generators to bid their full de-rated capacity (as determined by the Capacity Delivery Body subject to governance procedures to be determined[68]).

4.3.22 Additionally, the SEM Committee considered that the options may be applied differently to intermittent plant technologies and to dispatchable plant.

4.3.23 The SEM Committee view is that on balance, Option 3 is appropriate for dispatchable generators and Option 2 is appropriate for intermittent generators.

4.3.24 For a dispatchable generator, control of its output is largely manageable by the generator. The risk that would be placed on a generator by requiring it to bid should not be excessive, particularly when mitigated with “stop loss” limits. Therefore market power concerns largely outweigh the additional risk placed on generators via mandated bidding. However, to reflect the fact that not all generators of the same technology will have the same degree of reliability, and hence face different risk profiles, the SEM Committee will allow the generator a degree of tolerance to risk adjust its bid within a tolerance band. The sole exception to this will be if a dispatchable generator declares during qualification that it will close before the end of the delivery period. The SEM Committee will keep under review the requirement for sanctions to apply if any dispatchable declares that it will close in order to opt out, and subsequently does not.

4.3.25 To make the mandatory bidding effective as market power control, it is also necessary to ensure that:

[68] Either with or without the flexibility for individual generator to negotiate a plant specific de-rating factors

- Generators provide a technical justification of why their plant merits a different rating to the average for that technology. This information will be a key part of judging potential market manipulation;
- The generator declares where within the tolerance band it is going to bid at qualification stage, to allow the TSOs to adjust the capacity requirement if generators as a whole choose to bid below the centrally determined de-rating factor;
- Once the dispatchable generator has declared how many MW of RO it is going to bid for, it must enter the auction and continue to bid all of the notified MW into the auction until the price descends to a "maximum exit price", a form of reserve price. This was the approach employed to mitigate market power in the GB 2014 capacity auctions, and is a common market power mitigation tool in auctions. The SEM Committee will consult on the value of this "maximum exit price".

4.3.26 For an intermittent generator, the risk resulting from mandated bidding is bigger, notwithstanding the de-rating approach and stop-loss limits. Also, intermittent generators are expected to be a relatively small proportion of de-rated capacity, so if they choose not to bid, their non-participation with have a smaller impact on market power. Therefore, intermittent generators will have the discretion to not submit a bid. However, all intermittent generators above a de-minimis threshold will be required to pre-qualify, and notify how many MW of RO it is going to bid for, although this number could be zero.

4.3.27 The TSOs will use the qualification information from both dispatchable and intermittent generators to adjust the amount of capacity bought, where any generation that chooses not to participate or to bid higher or lower than its central determined de-rating. Adjusting the capacity requirement downwards has two key benefits:

- It mitigates market power by ensuring that surplus of bidding MW over capacity bought remains the same as if the generator had bid. Otherwise there is a risk that if a significant proportion of de-rated generation opts not to bid, the volume of bidders is less than the capacity purchased, giving bidders a high degree of market power[69].
- It ensures that consumers do not need to pay for capacity which will be provided by capacity which has opted out of the CRM, but which is expected to be available and able to contribute to alleviating system stress. For instance, if all wind plant chooses not to bid, this could be approximately 8% of de-rated capacity, or around 500MW in 2017. The cost of procuring an additional 500MW depends on the auction clearing price, if the auction clears at the SEM 2016 BNE price, the cost could be of the order of €30m p.a.

[69] Although this market power can also be mitigated by using a sloping demand curve, rather than a vertical demand curve.

4.3.28 A disadvantage of any reduction in the capacity requirement is that it increases the potential size of a shortfall in RO difference payments. However, by socialising the shortfall (see discussion in Section 3.7), this ensures that customers only pay if and when there is shortfall, which might be rarely or never. By contrast, if the capacity requirement is not adjusted consumers would bear the cost of up to €30m p.a. regardless of whether a shortfall in RO difference payments ever occurred.

4.3.29 The SEM Committee will consult further on whether any additional market power controls should be applied in CRM Consultation 3.

SEM Committee Decision

4.3.30 The SEM Committee has decided on the following principles:

- Existing dispatchable plant will need to bid within a tolerance band of the centrally determined de-rating factor for that plant[70], unless it declares that it will close before the end of the delivery period. This band will be tight, and will not exceed the lower of:

- A threshold as set periodically by the SEM Committee (e.g. +x%, -y%);
- Variation that, is sufficient to encompass legitimate variations in the technical characteristics of relevant plant[71].

- Once the dispatchable generator has declared the number of MWs to be bid, this number of MWs will need to be bid into the auction and remain in the auction until a pre-defined maximum exit price[72]. However, the requirement for mandatory bidding will not apply to dispatchable non-firm transmission access generation (see Section 4.4).
- Intermittent plant will need to submit qualification information saying how many MWs they are going to bid into the auction, but will have freedom to not participate (Option 2). Having indicated how many MWs they are going to bid, they will be required to bid these MWs into the auction until a pre-defined maximum exit price.

4.3.31 For the avoidance of doubt:

- This decision is without prejudice to the consideration of interconnectors and overseas generation which will be considered in Consultation 2;

[70] The practicality of using such tolerances will be kept under review as we develop the analytical approaches for deriving de-rating factors.

[71] Note: The practicality of identifying such a tolerance will be kept under review as we develop the detailed analytical methodology for this area.

[72] similar to the arrangement in 2014 GB capacity auction, whereby existing capacity having entered the auction needed to remain in the auction until ½ CONE (Cost of New Entry)

- There will be no requirement for any potential DSUs (except for existing DSUs) to bid or to submit qualification information (unless they wish to bid).

Next steps

4.3.32 The SEM Committee will consider what appropriate governance arrangements, e.g. licence modifications should be put in place to require mandatory qualification and bidding.

4.3.33 The SEM Committee will consult further on:

- The "maximum exit price" for auction bidders;
- The tolerance bands to be allowed around a central value for each technology/plant size.

4.4 TREATMENT OF GENERATION WITH NON-FIRM TRANSMISSION ACCESS

Consultation summary

4.4.1 Detailed projections from the TSOs suggest that there is as much as 900MW of conventional (i.e. dispatchable, non-renewable) generation, which currently has non-firm transmission access rights. This is projected to decline to around 550MW in 2017, when the I-SEM starts, and to 300MW in 2018. Some conventional generation is still predicted to have non-firm access by 2024, the end of the projection window.

4.4.2 The SEM Committee noted that, if some of this non-firm access generation is a potentially cost effective form of capacity, there is a strong argument to allow it to compete in the I-SEM CRM. This capacity has sunk investment costs, but needs to be able to recover its fixed operating costs. If they are not eligible, the plant would have to rely on the energy market to recover its fixed operating costs. If energy market revenue is insufficient to recover fixed costs it could be retired, and have to be replaced by new plant, that has to factor both investment costs as well as fixed operating costs into its CRM bid price.

4.4.3 The potential benefit of lower cost capacity has to be weighed against the risk that this capacity will be curtailed at times of system stress, whereas alternative new capacity in a different location where firm transmission access can be guaranteed not to be curtailed.

4.4.4 SEM-15-044 noted that in practice, some of the non-firm transmission access conventional generation is non-firm because it is behind a transmission bottleneck with priority dispatch renewable generation-predominantly wind generation. Therefore there is likely to be a negative correlation between curtailment of the conventional generator and system stress. If the wind is not blowing, system stress is more likely, but it is less likely that the conventional generator will be curtailed.

4.4.5 The options set out in SEM-15-044 for non-firm access generation were:

- Option 1: Eligible to bid, subject to the same de-rating factors as firm generators of the same technology;
- Option 2: Eligible to bid, subject to additional de-rating (for transmission access, as well as technology specific). The additional de-rating would depend on the relationship between the exit capacity from the constrained zone, demand in the zone and wind generation in system stress scenarios;
- Option 3: Ineligible to bid.

4.4.6 In addition, there is the separate but related question whether, if non-firm transmission access generators are eligible to bid, whether dispatchable non-firm transmission access generators should be exempt from the mandatory bidding requirements for dispatchable generators set out in Section 4.3.

Summary of responses received

4.4.7 The majority of respondents favoured Option 1: Eligible to bid subject to the same de-rating factors as firm generation. Respondents stated that generators with non-firm access should be allowed to participate like anyone else, and that any constraints should be managed at their own risk.

4.4.8 A number of respondents favoured Option 2: Eligible to bid, subject to additional de-rating. They recognised the risk potentially placed on non-firm transmission access generators and argued that non-firm generation should be free to offer RO quantities lower than their centrally-determined de-rating factor, allowing participant's factor in the risk of non-delivery.

4.4.9 Relatively few respondents favoured Option 3: ineligible to bid. One respondent stated that the market price at that time of scarcity will provide an appropriate incentive for non-firm generation to run.

SEM Committee response

4.4.10 The SEM Committee agrees that non-firm transmission access generation has a potentially valuable role to play in providing capacity, and that it should be able to participate in the capacity market. Therefore it has decided to allow non-firm transmission access generates to participate (narrowing the choice to Option 1 or 2)

4.4.11 However, the risk for non-firm transmission access generation is significantly greater than that for firm access generation, and like intermittent generators, this risk is to a significant extent, outside the generator's control. Non-firm transmission access generators already face more risk than firm generators in the energy market and applying exactly the same CRM regime to firm and non-firm transmission access generators would impose an excessive risk burden.

4.4.12 The risks could be mitigated either by:

- Applying a further de-rating factor (Option 2); or
- By relaxing the requirement for non-firm transmission access generation to bid within mandatory tolerance bands by removing the lower limit on the quantity of capacity they can offer. This will allow them to reflect their own risk assessment in the offered quantity.

4.4.13 Whilst applying an additional de-rating factor to account for an expected level of curtailment (Option 2) may serve to de-risk CRM participation for non-firm transmission access generators, significant residual risk remains. Therefore the SEM Committee prefers:

- Option 1 (Eligible to bid, but subject to the same de-rating factors as firm generators of the same technology); but
- Coupled with a relaxation of the requirement on dispatchable generators to make mandatory bids (i.e. apply Option 2 as opposed to Option 3 in Section 4.3).

4.4.14 The key driver for making it mandatory for dispatchable plant to bid is to mitigate market power, but relaxing this requirement for non-firm transmission access generators will have relatively limited effect on market power, as non-firm transmission access generators are a relatively small proportion of the market. Therefore the SEM Committee has placed a greater importance on allowing non-firm transmission access generators to manage risks outside their control.

4.4.15 We note that in SEM-15-044, we stated that "Options for the treatment of non-firm access generation in the I-SEM energy market were set out in the ETA Building Blocks Consultation Paper. In particular, the SEM Committee is considering whether non-firm generation would be compensated if constrained relative to ex ante market positions (the Day Ahead and Intra-Day markets). Eligibility for non-firm generation in the capacity mechanism will depend on the ability of this capacity to access the reference market for the RO and therefore we will ensure that the treatment of non-firm generation in CRM is consistent with the SEM Committee Decision on the Energy Trading Arrangements." In the recent paper SEM-15-064, the SEM Committee decided that ex ante positions taken by non-firm generators would be cashed out at the imbalance price, and that part of the rationale for this decision was to incentivise the generators to price this risk into their DAM and IDM offers. However, the decision to adopt Option 4b for the MRP means that a non-firm access generator can choose not to expose itself to the risk of bidding into the DAM without being compensated, and still achieve the reference price by selling into the IDM or BM. Therefore the decision set out in SEM-15-064 does not preclude non-firm transmission access generators from participating in the I-SEM CRM.

SEM Committee decision

4.4.16 The SEM Committee has decided that non-firm transmission access generators be:

- **Eligible to bid, subject to the same de-rating factors as firm generators of the same technology;**
- **Exempt from any requirements to bid in the CRM auction**, in respect of any volume in excess of their firm generation access. They will still need to submit qualification information in order for the TSOs to adjust the volume of capacity procured appropriately.

4.5 DEMAND SIDE PARTICIPATION

Consultation summary

4.5.1 Demand Side Participation can lead to the more efficient provision of capacity, where the opportunity cost of reducing consumption is less than the cost of new generation capacity provision. Additionally, the lack of effective demand side participation is often cited as a contributor to generators' wholesale market power in both energy and capacity markets.

4.5.2 The EEAG include the requirement that generation adequacy measures should be open and provide adequate incentives to operators using substitutable technologies, such as demand-side response or storage solutions.

4.5.3 A key consideration for the CRM is how to facilitate appropriate Demand Side Participation. There are three categories of demand side units that currently operate in the SEM.

- End consumers who have the capability to reduce demand at times of system stress. This could include large industrial customers, small and medium sized business customers, and residential customers, if they have the capability to respond to price or other signals of system stress.
- Generation capacity which does not have the capability to export to the grid (and hence may be treated differently from other generation), but which has the capability to reduce the end consumers' net demand from the grid at that site if it generates, e.g. back-up generation.
- Generation capacity with the ability to export its generation, and also has the capability to reduce end consumers' net demand if it generates.

4.5.4 The current SEM allows DSUs to participate in the capacity market. However, under the current I-SEM ETA design, those DSUs would only receive compensation in the energy market corresponding to the value of energy reduction, if they are also the Supplier.

4.5.5 The RAs sought feedback on the relative merits of the following three options:

- Option 1: DSUs do not receive an energy payment for foregone consumption, and are subject to the same RO difference payments and any other incentives for physical performance as generators;
- Option 2: DSUs receive a new energy payment for foregone consumption, but are subject to the same RO difference payments and any other incentives for physical performance as generators; and
- Option 3: DSUs do not receive a new energy payment for foregone consumption, but are exempt from RO difference payments. However, they are subject to other incentives for physical performance imposed on generators.

Summary of responses received

4.5.6 A number of respondents favoured Option 1: DSUs do not receive energy payment. One respondent described how DSUs should also be permitted to participate and be exposed to the same paybacks and incentives as all other technologies.

4.5.7 A number of respondents favoured Option 2: DSUs receive new energy payment. Respondents pointed out that if DSU participants do not get an energy payment they would not have the energy revenue to be able to make RO difference payments, and that Option 1 would make the business model of the non-Supplier DSU aggregator unviable. Some respondents stated that they had a preference for Option 2 as an enduring solution, but doubted that it could be implemented in time, so thought that Option 3 would be a pragmatic solution.

4.5.8 A number of respondents favoured Option 3: No new energy payment, DSUs exempt from difference payment but may be subject to other incentives. One respondent stated that DSUs should be subject to other incentives for physical performance.

4.5.9 A number of respondents were keen to ensure that DSUs are subject to the same performance incentives as to those faced by generators.

4.5.10 One respondent raised the question of how autoproducers (Trading sites) would be treated. In particular, they argued that:

- The RO auction entity must be matched with an entity in the energy market and the treatment of Autoproducers should be considered in both markets;
- Autoproducers with a Maximum Export Capacity which was much less than their nameplate capacity should not be required to sell their full capacity and pay for capacity through an RO supplier hedge.

SEM Committee Response

4.5.11 The SEM Committee is keen to facilitate a range of DSU business models including the current one, and ensure that DSUs are appropriately incentivised to deliver demand response when called.

4.5.12 Under the I-SEM ETA arrangements as developed to date, independent DSUs (i.e. DSUs who are not also Suppliers) would not receive any credit in the BM for reduced consumption, i.e, the difference between metered consumption and ex-ante purchases. This value will be credited to the relevant Supplier(s) under the current arrangements. SEM-15-064 (Building Blocks Decision Paper), also stated that, "*the SEM Committee agrees that the DSU should not have to reach agreements with the Suppliers of all customers included in any DSU.*" In the absence of an agreement between the Supplier and the DSU with regard to the value of reduced consumption, the DSU would not receive any credit for the energy value of any demand response provided. This would mean that they do not have any energy revenue to offset against any RO difference payment liability, so Option 1 would render the current DSU business model separate from Suppliers non-viable, and Option 1 is discounted.

4.5.13 The SEM Committee, like a number of respondents is concerned that a pure version of Option 3 would not contain sufficient incentives on DSUs to deliver the contract demand response. Option 3 would also be another source of a potential "hole in the hedge", as DSUs would not make RO difference payments.

4.5.14 The SEM Committee considers that there are two approaches which could be made to work conceptually.

4.5.15 The first approach is a version of Option 2, whereby a change is made to settlement arrangements which credits the energy value of the demand response to the DSU (not the Supplier). Among other benefits, such an approach would give the DSU the money to make the RO difference payment. An example of how a version of Option 2 could work is set out in Appendix D. However, implementing Option 2 may involve significant changes to settlement arrangements, which may not be feasible for the start of the I-SEM.

4.5.16 If Option 2 is not feasible, it could be possible to implement an approach based on a hybrid of Option 1 and Option 3 which recognises that DSUs do not receive the energy value of the demand reduction, but contains additional incentives which mimic the effect of the RO difference payment. This hybrid option would work as follows:

- When a DSU delivers its contracted RO volume of demand reduction, it is exempt from the RO difference payment; but
- To the extent that a DSU does not deliver its contracted RO volume it will be obliged to make a difference payment, on the undelivered demand side response.

4.5.17 Such an approach assumes that it is possible for the TSOs to identify to what extent the demand response has or has not been delivered.

4.5.18 Consider the following example, which illustrates how this approach will deliver similar outcomes for a 1MW DSU and a 1MW generator with similar variable cost. Let us assume that the DSU has contracted with an end consumer, X, who normally consumes at a rate of 3MW, but can provide 1MW of demand reduction if required, reducing its consumption to 2MW on instruction. Let us assume that the cost to X of 1 hour of load reduction is €490/MWh (which would be what it bids into the SEM at the moment), and the DSU agrees to compensate X at a rate of €490/MWh if the demand reduction is called. Let us assume that the RO Strike Price is €500/MWh and the ASP is €10,000/MWh

4.5.19 At the Day Ahead stage there is no scarcity, and X expects to consume its normal 3MW, but at some point after the DAM, scarcity occurs, and the BM price rises to €10,000/MWh. The DSU instructs X to reduce load by 1MW. Let us assume that X only partially follows the DSU's instruction and reduces load by only 0.4MW. Now under this hybrid approach, the DSU would not have to pay any difference payment on the 0.4MWh of delivered demand reduction[73], but would have to pay a difference payment of 0.6 x(10,000 – 500) = €5,700 as its penalty for failing to deliver on 0.6MW of its RO volume. Now contrast that with a 1MW generator, with a fuel cost of €490/MWh, which has sold its volume in the BM. The generator will have to make RO difference payments on the full 1MW of RO volume. It will make a small amount of money (0.4 x €10/MWh, i.e. the difference between its fuel cost and the Strike Price) on the 0.4MWh of energy it delivers, but have paid a difference payment of 0.6 x (10,000 – 500)=€5,700 on the 0.6MWh of undelivered volume. **Therefore the way we have constructed the penalty on the DSU in this hybrid option ensures that it mimics the penalty on a generator whose fuel cost is the same as the DSU variable cost**. However, this settlement could be applied in CRM settlement systems, without the need to change ETA systems.

SEM Committee decision

4.5.20 The SEM Committee is of the view 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.

In the medium to long term, the SEM Committee considers that there may be merit in further exploring Option 2 and as such may review this decision post I-SEM Go-live.

[73] Assuming a 1 hour scarcity event

Next Steps

4.5.21 The SEM Committee will consider the treatment of autoproducers in the context of future CRM Consultations.

4.6 OTHER POTENTIAL CAPACITY SOURCES AND ENERGY LIMITED PLANT

Consultation summary

4.6.1 SEM-15-044 noted that other technologies, such as energy storage, may also contribute to system security by providing stored energy at peak times. Such technologies should be able to enter the market if there is a realistic prospect of them contributing materially to system security, but there are issues in determining whether they contribute fully. For instance:

- How long is a stress period expected to last?
- Can a technology be guaranteed to deliver for the whole period of system stress, or will energy storage limitations impact their contribution?
- If energy storage constraints do limit the length of time for which they can contribute at full capacity, how should this be reflected in their eligibility / de-rating?

4.6.2 SEM-15-044 stated that the RAs intend to work with the System Operator (SO) to define the minimum requirements that energy limited plant must meet, and how their de-rating factor should be determined.

Summary of responses received

4.6.3 Whilst not asking any specific questions relating to energy storage, the RAs received representation from owners of actual/potential energy storage assets, on the following points:

- That energy storage units should be allowed to be included in aggregator portfolios;
- They should not be charged an RO fee for energy consumed in re-charging their storage, given that they will not be drawing power during a stress event;
- Energy limited generation such as storage should not be subject to penalties for non-delivery of energy that is beyond their energy limit.
- Storage units should be classified as DSUs when in demand mode where they can demonstrate fast acting and flexible demand reduction in response to under frequency events or other signals from the TSO as appropriate.

SEM Committee response

4.6.4 The SEM Committee agrees that energy storage units should be allowed to be included in aggregators' portfolios.

4.6.5 The SEM Committee notes the arguments from energy storage owners arguing that they should be exempt from Supplier charges. Consumption by existing storage units are treated as negative generation, so do not face Supplier charges for capacity in the SEM. We have further considered this issue in our discussion of Supplier charging in Section 5.2.

4.6.6 The SEM Committee does not agree that energy storage units should be exempt from RO difference payments where they have exceeded their energy limits. Energy limits may be taken account of in the de-rating factors, but to the extent that a scarcity event last longer than an energy limited plant is able to deliver, or at a point in time when energy stores are low, this risk should be borne by the capacity provider. Such an approach is technology neutral and any technology specific exemptions could incentivise over-build of plant which is not fully able to help alleviate system stress. However, the SEM Committee recognises that if we place the responsibility for managing this risk on the energy storage capacity provider, there may be strong grounds for a capacity provider to have the flexibility to bid below any centrally determined de-rating factor in the CRM auction. However, the SEM Committee will need to consider its position further in the context of Turlough Hill, given its size and ownership by ESB, who are potentially a pivotal capacity provider in the CRM auctions.

4.6.7 The SEM Committee does not agree that an energy storage unit should be treated as a DSU, or at least a DSU with a baseline consumption of anything other than zero. It should not be eligible for a credit of energy value for reducing its "consumption" during a period of system stress.

Next steps

4.6.8 The RAs will work with the TSOs to develop the minimum eligibility requirements for energy limited plant and de-rating approach.

4.7 DE-RATING

Consultation summary

4.7.1 An approach needs to be developed for defining the maximum MW of RO volume that a given capacity provider will be allowed to back. The approach should be reflective of its ability to deliver capacity at times of system stress. As set out in SEM-15-044, this could be based on the total "nameplate" capacity, or "de-rated" for factors such as "forced outages" to reflect its likely contribution to meeting demand at time of system stress.

4.7.2 As set out in Section 2, the SEM Committee has determined that the capacity requirement should be specified in terms of de-rated capacity, so the maximum MW of RO volume that a given capacity provider will be allowed to back should also be specified in terms of de-rated capacity, not nameplate capacity.

4.7.3 SEM-15-044 stated that it will be necessary to determine a de-rating approach to:

- Dispatchable capacity, including:

- Thermal generation;
- Pumped storage- particularly Turlough Hill;
- Existing hydro, which is not supported by renewables / low carbon regimes;
- Other Energy limited plant;
- Demand side participation; and

- Intermittent capacity; and
- The Moyle and East-West interconnectors

4.7.4 SEM-15-044 stated that, where possible, a common framework for de-rating should be employed, and asked for feedback on the following generic issues:

- Should the de-rating factor by technology specific or plant specific?
- **Historic vs. projection approach**. Should a given plant's de-rating factor be specified based on its historical performance, its projected future performance, or a hybrid of the two approaches?
- **Marginal vs. Average approach**. Should a plant's de-rating factor be based on its average capacity contribution or its marginal capacity contribution? We explained that a de-rating factor could be based on a unit's marginal capacity contribution, or its average availability. The average capacity contribution of generation unit at times of system stress is likely to be broadly equal to its forced outage rate (assuming that a generator would not plan outage at times of peak demand when system stress is most likely). The marginal contribution of a plant is the impact that plant has on the total requirement for nameplate capacity. For example, if peak demand grows by 100MW, if an extra 110MW of nameplate capacity of technology type t is required to maintain the security standard, then the de-rating factor for a 100MW plant of technology t is 100/110 =90.9%. The marginal de-rating factor depends upon correlations of a plant's output with system stress periods, and diversification effects.
- **Grandfathering**. Should a plant with a multi-year RO contract have its de-rating "grandfathered", i.e. guaranteed, over the life of the RO, or should the relevant authorities be able to change the de-rating factor over the lifetime of the contract?

Summary of responses received

Technology or plant specific

4.7.5 A majority of respondents favoured plant specific de-rating factors. One respondent argued that there may be reasonably large discrepancies in the performance of individual units, and that it would seem inequitable on CRM participants not to recognise performance differences via plant specific de-rating factors.

4.7.6 One respondent argued that plant specific de-rating factors would also provide an incentive for a plant to find innovative means of increasing its capacity value. Another respondent stated that it should be possible to award plant specific factors in a small market with limited units.

4.7.7 A number of other respondents favoured technology de-rating factors. However some of those who argued in favour of a technology specific approach did so based on the assumption that a plant owner would have the discretion to further de-rate its own plant, by bidding less than the centrally determined maximum de-rating factor.

4.7.8 One respondent argued that for certain technologies it may be appropriate to use a technology specific approach to de-rating (i.e. for wind turbines which have a strong interdependence of availability).

4.7.9 A number of respondents made the point that DSUs do not have intrinsic forced outage rates and argued that there should be no need for de-rating of DSUs.

4.7.10 In general respondents argued that whatever approach is used, it should be done in a transparent manner.

Historic versus projection approach

4.7.11 Respondents generally favoured a historical approach, rather than one based purely upon projected data, possibly supplemented by other data (i.e. a hybrid approach), where there was either insufficient history, or clear evidence to over-ride history.

4.7.12 Some respondents stressed the importance of a clear and transparent approach, particularly if the methodology allowed for the over-riding of historical data. One respondent stated that historical data is more reliable than future expectations of availability.

4.7.13 Another respondent stated that the historic approach provides clearer exit signals if historical performance has been poor, with projections open to the subjectivity of assumptions. This respondent also stated that a hybrid approach may be worth reviewing.

4.7.14 One respondent described how historic performance could be used as the benchmark when determining de-rating factors, with new generators being linked to plants of similar characteristics until sufficient history is available.

4.7.15 A number of respondents stressed the lack of forced outage rates or other relevant historical data for DSUs.

Marginal versus average approach

4.7.16 One respondent argued that a unit's capacity credit should be a function of physical, technological and fuel related unreliability and other variables (e.g. age) and the correlation of these with other units' capacity unreliability.

4.7.17 This respondent described analysis in the Generation Capacity Statement 2015-2024 of how the capacity credit of an additional MW of wind capacity decreases as more wind capacity is added to the system (with local wind energy being highly correlated).

Grandfathering

4.7.18 A number of respondents favoured grandfathering. Respondents described how grandfathering of de-rating factors will help to provide investor certainty. One of these respondents stated that grandfathering reduces barriers to new entry and encourages competition.

4.7.19 A number of other respondents did not favour grandfathering. One respondent argued it distorts the true contribution of the unit to generation adequacy. However they highlighted the need for stable and predictable RO income for new plant so that project funding costs and consequently consumer costs can be minimised.

4.7.20 Another respondent stated that allowing a unit to retain higher derating factors in subsequent years may expose them to higher risk in relation to the RO difference payments. One respondent stated that grandfathering for multi-year contracts could introduce an inconsistency between the TSO's current best view of de-rating for capacity already contracted, and the basis on which multi-year capacity is paid.

SEM Committee response

Technology or plant specific

4.7.21 The SEM Committee agrees that it is appropriate to have certain plant specific de-rating factors. In particular the SEM Committee is convinced by the following arguments:

- That it provides the right incentives for plant owners to invest to maintain or improve plant performance; and

- Early analysis by Eirgrid suggests a significantly greater capacity contribution for a smaller unit than for a large unit of the same technology and with the same forced outage rate. This is because the outage risk of a large number of small units diversifies more than the outage risk for a smaller number of large units. This statistical effect is more pronounced in a smaller system with a fewer number of capacity units, such as the island of Ireland than in larger systems with more units, such as GB.

4.7.22 The RAs will work with the TSOs to develop a detailed methodology for developing plant specific de-rating factors.

4.7.23 The SEM Committee also notes that the approach of allowing non-intermittent generators to bid within a tolerance band of any centrally determined de-rating factor (and to allow any intermittent generator the freedom to bid down to zero) also allows capacity owners to introduce an element of plant specificity into de-rating, at the plant owner's discretion.

Historic versus projection approach

4.7.24 The SEM Committee agrees that it is appropriate to base de-rating factors on historical performance factors, where such data is available and it is reasonable to believe that this data is a reliable guide to future performance. However, the SEM Committee believes that where there is a reasonable evidence base to suggest that the future will not be like the past, that evidence should be incorporated into the de-rating factor. Therefore the SEM Committee proposes to use a hybrid approach.

4.7.25 The SEM Committee agrees that a transparent methodology should be adopted, setting out the guidelines for when other evidence should be allowed to over-ride history.

4.7.26 The SEM Committee also notes that the approach of allowing non-intermittent generators to bid within a tolerance band of any centrally determined de-rating factor (and to allow any intermittent generator the freedom to bid down to zero) also allows capacity owners to introduce a degree of their own judgement as to whether the past is a good guide to future performance.

Marginal versus average approach

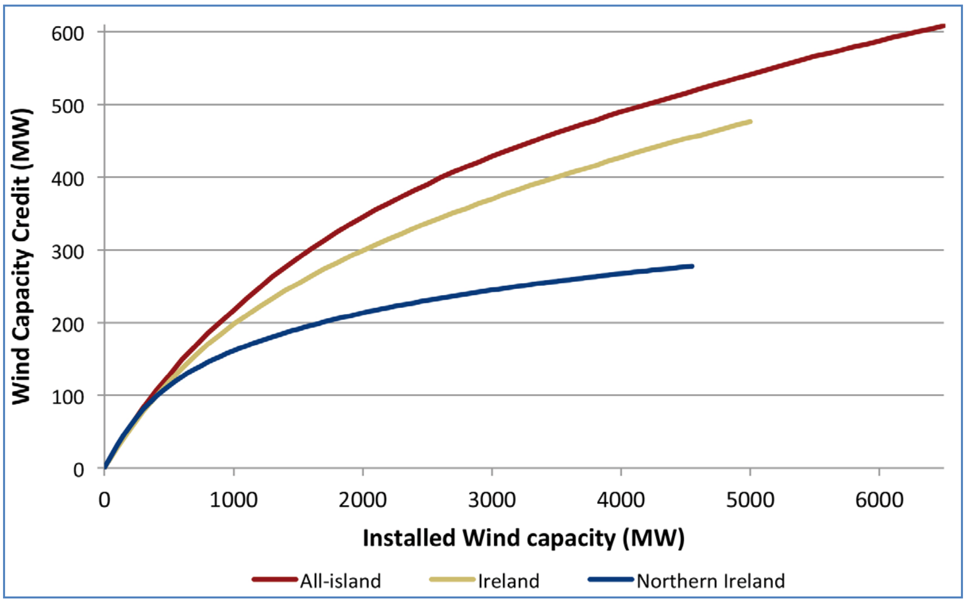
4.7.27 Analysis provided by Eirgrid in their consultation response shows that diversification effects make a material difference to the capacity contribution of different capacity units with the same forced outage rate. This analysis had persuaded the SEM Committee of the importance of reflecting a capacity unit's marginal impact in its de-rating factor, and that use of average availability at times of system stress insufficiently captures a unit's contribution.

Grandfathering

4.7.28 The SEM Committee note that centrally determined de-rating factors for each technology are unlikely to change significantly over time – with the main driver of such changes being changes to the plant mix within the I-SEM system. Investors in new capacity providers would typically be expected to consider such changes as part of their investment appraisal – as they will impact the plant's future revenue, and its risk of economic stranding. For example:

- As noted above, de-rating factors are impacted by the size of plant meaning that an I-SEM system with lots of small plant would need a lower capacity margin than one with a few large plants. Changes to the plant mix that lead to a lower average plant size may lead to a marginal increase in de-rating factors;
- As shown in **Error! Reference source not found.** below, the capacity credit of wind plant (which is likely to be related to that plant's de-rating factor) decreases with the increased penetration of wind. Given the current level of wind penetration in the I-SEM, subsequent changes to the de-rating factor for wind are likely to be small.

Figure 12: Capacity credit of wind generation for Ireland and Northern Ireland, compared to the all-island situation (Figure 3.8 from the All Island Generation Capacity Statement, 2015-2014).



4.7.29 The SEM Committee notes that any decision on grandfathering will require a trade off between a number of the agreed assessment criteria, notably:

- **Security of Supply:** It is possible that the de-rating factor for specific technologies will change between the award of an RO and the time at which it matures. Where this change implies the relevant technology makes a reduced contribution to the security standard, there will be a need for additional capacity to maintain security of supply.
- **Equity:** Decisions on grandfathering will impact the balance between consumers and capacity providers for who takes the costs (of needing to buy additional

capacity) or benefits (of having additional capacity available to sell) that arise from changes to the de-rating factors during the life of a specific RO.

- **Stability:** To provide investor confidence, de-rating factors should ideally be fixed at the time each RO is awarded, or be such that any changes during the life of that RO are either due to:

- Factors that are normally managed by investors in capacity (e.g. future changes in the plant mix); or
- Factors that are best managed by the relevant plant (e.g. own plant reliability).

- **Adaptive:** The arrangements should allow the de-rating factors to change over time. This is required so the centrally determined de-rating factors used for each RO auction reflect the best view (at that time) of the extent to which different technologies contribute to the security standard.
- **Competition:** There should be equivalent treatment of the de-rating factors for new and existing capacity providers.

SEM Committee decision

4.7.30 The SEM Committee has decided that the development of de-rating factors should proceed on the basis that:

- **Central de-rating factors will be technology specific, but make allowance for the impact of plant size**. At minimum, plant of the same technology but of significantly different unit sizes should have different de-rating factors, and may reflect plant specific history or known future events – such as extraordinary planned outages.
- Be based on **marginal contribution** to meeting the capacity requirement;

- Be centrally determined by the TSOs, with the TSOs determining de-rating factors for groups of technologies.
- Be based on TSO analysis of the marginal contribution of the relevant technology to the capacity requirement. That is the extent to which a marginal increment or decrement of nameplate capacity from that technology type impacts the overall requirement for nameplate capacity
- Vary for characteristics of a technology (e.g. size) that can be parameterised, and which legitimately impacts its marginal impact on the capacity requirement.

4.7.31 The SEM Committee's decision on **grandfathering of de-rating factors** has a number of components:

- **Existing plant:** Existing plant will compete for and be awarded annual ROs. In each case, these ROs will be based on the de-rating factors that:

- Applied to the relevant technology; and
- Was centrally determined for the relevant auction.

- **New plant:** The quantity of RO awarded to new plant should be fixed for the life of that RO; however, the RO holder should carry the risk and benefit of changes to the underlying technology de-rating factors for all but the first year of that RO. This approach:

- Provides an equitable treatment between new and existing plant – by fixing the de-rating factors for the first year of the RO;
- Allocates the risks and benefits arising from changes to de-rating factors (over the remaining life of the RO) to new plant.

Next Steps

4.7.32 The RAs will request the TSOs to develop on the detailed methodology for setting of de-rating factors for relevant generators, DSUs and other potential capacity providers, and will consult on that methodology.

4.7.33 Having established the detailed methodology, the RAs will request the TSOs to determine central de-rating factors for each plant for the first CRM auction- individual plant will be allowed to bid within a tolerance band of this central de-rating factor.

4.8 TREATMENT OF AGGREGATORS AND PPA PROVIDERS

Consultation summary

4.8.1 The consultation paper examined potential treatment of Capacity Aggregators and PPA providers in the CRM. SEM-15-044 noted that aggregators, such as PPA providers, would be able to fulfil a role in the mechanism as an intermediary by:

- Contracting physical capacity from small capacity providers including Demand Side Response, as well as small generators and energy storage providers; and
- Bidding the aggregated portfolio into the RO auctions.

4.8.2 Consultation feedback was sought on the following key issues:

- What evidence a Capacity Aggregator should be required to provide to prove that it has the physical capacity backing for the RO? The paper asked respondents if the Capacity Aggregator should produce contractual evidence, such as a PPA to prove that it has physical backing? Or if this was too onerous an obligation to place on the Capacity Aggregator?
- Should there be a maximum size of unit that can bid into the RO auction via an aggregator, and if so what is that threshold? For example, the SEM uses a 10MW threshold, above which a unit must bid directly into the Pool. SEM-15-044 stated that 10 MW would seem a reasonable value above which an existing

capacity provider must bid directly into the RO auction if it chooses to participate in the I-SEM CRM; and

- Should there be a minimum size below which a capacity provider may not bid directly into the RO auction, and must bid via a Capacity Aggregator? The 2014 GB capacity auction required capacity providers with less than 2MW to bid via an aggregator. SEM-15-044, suggested that given the relative size of the All-Island market, it may be difficult to justify a higher limit, but that there was the question as to whether a smaller limit could be set?

Summary of Consultation responses received

Physical backing required

4.8.3 A number of respondents stated that there should be a requirement to show physical backing. A number of respondents favoured evidence of physical generation being provided by PPAs or similar contracts. A number of respondents favoured aggregators being required to demonstrate physical backing by test prior to the start of its contract.

4.8.4 One respondent stated that the aggregator should be required to show evidence of physical backing, such as a letter of agreement between counterparties. Another respondent favoured using the process used today for demand side and aggregated generator units for the purposes of establishing physical backing.

Maximum size of unit participating via a Capacity Aggregator

4.8.5 There was no clear consensus on whether there should be a maximum size of unit that can bid in via aggregator. A number of respondents favoured a maximum size of unit that can bid in via aggregator, and some argued that a limit of 10MW maximum capacity seems reasonable and appeared compatible with the current SEM. One respondent arguing in favour of a limit stated that there is a potential for large aggregators to have market power, and therefore there may need to be a limit to the size of an aggregated portfolio, or to have structures in place to limit the market power. One respondent stated that targeted market power mitigation measures should extend to dominant entities providing or using aggregation services.

4.8.6 However, a number of respondents did not favour a maximum size of unit that can bid in via aggregator. One respondent described how requirement for a maximum size of unit that can bid into the RO is not apparent.

4.8.7 A number of respondents favoured no restrictions on the size of intermittent renewable generation that can be included in an aggregator, in order to account for the geographical variations in the natural resource.

Minimum size of unit participating directly in the CRM

4.8.8 A number of respondents favoured a minimum size below which a capacity provider cannot bid directly into the RO auction. One respondent stated that for practical reasons it may be necessary for small scale capacity below a certain threshold to be considered ineligible to bid directly into the RO auction, giving a preference for a threshold of 2MW.

4.8.9 Another respondent stated that it was reasonable to have a minimum size to reduce the administrative burden of liaising with a large number of small counter-parties, giving a preference for threshold of 1MW. Another respondent described how going below a 1MW threshold doesn't seem practical from an implementation perspective as a minimum size to bid into the auction. One respondent stated its preference that the minimum size for generators should be 100kW, describing how this would enable widespread participation of small scale demand response.

4.8.10 By contrast, a number of respondents did not favour a minimum size below which a capacity provider cannot bid directly into the RO auction. A number of respondents stated that there should be no minimum level for participation in the CRM, that small scale generators should have the option to participate directly or through an aggregator.

4.8.11 One respondent described how creating a minimum size assumes that there will be an aggregator to meet individual generators needs to aggregate all de-minimis generation, and that this might not be the case, and that all generation units should participate on an equal footing.

4.8.12 One respondent described how any participation size thresholds for the CRM should be consistent with the approach taken in the ETA Building Blocks decision.

General comment on Capacity Aggregator sizes

4.8.13 One respondent identified the issue of how any changes to the de-minimis threshold could have an impact on implementation timescales. It was argued that a change in the de minimis threshold would cause movement between participant and non-participant generation which would need to be reflected in the processing requirements and registration of these units in the Retail Market as well as the I-SEM. This respondent stated that all changes that are required should be reflected in time for Market Trials.

SEM Committee Response

4.8.14 The SEM Committee is of the view that decisions taken in the ETA Building Blocks and Aggregator of Last Resort (AOLR) papers need to be taken into account before considering the treatment of aggregators in the CRM.

4.8.15 Our Building Blocks decision paper set out that generators are mandated to participate in the SEM if they have a Maximum Export Capacity (MEC) of 10MW or greater under a single connection point. All generation below this threshold can avail of independent aggregation services. The 10MW threshold will also apply to the AOLR however all sizes of renewable generation would also be able to avail of this service. There is no minimum threshold for participation in either the AOLR or as part of an independent aggregator.

4.8.16 It should be noted that a Capacity Aggregator may be different to an aggregator under the Energy Trading Arrangements. The Capacity Aggregator may aggregate across a range of capacity – including Aggregated Generation Units (AGU). For example, for the purposes of bidding into Capacity Auctions and settling the resulting ROs, a Capacity Aggregator could include an AGU alongside a separate registered unit.

Evidence of physical backing

4.8.17 The SEM Committee agrees that aggregators should be required to show evidence of physical backing in order to qualify for the auction. Whilst it may be possible in the case of existing capacity to require evidence of a PPA:

- This may be too onerous in the context of potential new build which needs an RO contact to raise finance; and
- What is really required is confirmation of the unit owner's consent for its unit to be aggregated (for the purposes of Reliability Options) by the relevant Capacity Aggregator.
- The two above factors imply that a Letter of Intent may be appropriate – especially in the case of new build.
- In any case it will be necessary to ensure that any capacity is only committed to one aggregator in any auction, rather than potentially "double-offered".

4.8.18 The SEM Committee notes that there are existing processes for testing of DSUs and Aggregated Generation Units (AGUs) set out in the Grid Code, and considers it is likely to be appropriate to continue to require physical testing. However, this cannot be a pre-requisite of entry into the auction, particularly where investment is required to create the capability.

Maximum size of unit participating via a Capacity Aggregator

4.8.19 As we have stated above, our ETA AOLR decision paper placed no limit on the size of renewable generation which can participate in the energy market via the Aggregator of Last Resort. All other generation are subject to a 10MW MEC threshold under a single connection point. The Building Blocks paper outlined that to participate in an independent aggregator the 10MW threshold held, regardless if you were a renewable generator or not.

4.8.20 Allowing larger renewable sites to participate in the CRM via an aggregator would facilitate volume risk diversification by intermittent renewables, potentially allowing aggregators to share risk pooling benefits with individual sites, and facilitating greater CRM participation by intermittent renewables. The SEM Committee sees benefit in extending the AOLR approach to CRM aggregators, and not limiting the maximum size of intermittent renewable units that can participate via a Capacity Aggregator. We do not foresee the AOLR itself participating in the auction. The SEM Committee does not see any reason why smaller units should not be able to bid into the auction independently, if they choose to do so.

4.8.21 For other generation it would appear administratively simplest to apply the same 10MW Maximum Export Capacity de-minimis threshold as is currently applied in the SEM and ETA arrangements.

Minimum size of unit participating directly in the CRM

4.8.22 The SEM Committee recognises that our ETA Building Blocks decision paper stated that, "Regarding the option set out in the Consultation Paper of having a kW or MW threshold level below which participants can only participate through aggregation, the SEM Committee is minded not to introduce such a proposal at this time. The SEM Committee recognises that very small players will probably choose not to trade in the market in their own right given issues such as fixed charges or minimum trade levels in the DAM and IDM but does not see the need to establish market rules to prevent this."

4.8.23 At the current time, the SEM Committee is minded not to introduce any such minimum size requirements for the CRM either, but recognises that depending on the CRM auction design, lots of small bidders may prove administratively complex and/or result in optimisation problems that are highly computationally intensive. Therefore the SEM Committee will keep this minded-to position under review during the auction design and implementation.

Other

4.8.24 The SEM Committee recognises respondent's concerns about aggregation services being provided by any capacity provider with an existing significant capacity market share, and will consider this issue in the context of other potential market power mitigation measures in the context of Consultation 3 (Auction Design).

SEM Committee Decision

4.8.25 The SEM Committee has decided that:

- Capacity Aggregators will be required to produce evidence of physical backing in order to enter the CRM auction. For existing capacity, this will include being able to show evidence of a PPA, covering the capacity delivery period.

- At the current time, the SEM Committee is **minded not to introduce any such minimum size requirements for direct CRM participants**, but will keep this minded-to position under review during the auction design and implementation.
- At least initially, there will be no maximum limit for the size of intermittent renewables plant that can participate via a Capacity Aggregator. This decision will be kept under review in light of its potential impact on the level of competition in Capacity Auctions
- The maximum size for all plant other than intermittent renewables plant that can participate via a Capacity Aggregator will be the same 10MW de-minimis threshold that applies in the I-SEM ETA.
- All generation, regardless of size, can bid independently into the CRM if they choose not to use an aggregator.
- Capacity Aggregators can only aggregate units that are or will be separately identified for the settlement of all I-SEM energy markets.

Next steps

4.8.26 The SEM Committee will consider further the requirements for new build capacity, including whether it is appropriate to require Capacity Aggregators to prove capacity by physical testing at any point prior to the start of the delivery period.

4.9 QUALIFICATION

Consultation summary

4.9.1 SEM-15-044 stated that there will be a number of key requirements that providers must demonstrate to be eligible to partake in the CRM auctions. We stated that the potential requirements for existing plant might include data to support de-rating, environmental compliance and other requirements.

4.9.2 SEM-15-044 also stated that there may be additional requirements in respect of new capacity, for instance such as those relating to planning consents, connection agreements, property rights and financial commitments and outlined some potential criteria.

Summary of responses received

4.9.3 A number of respondents favoured a robust qualification, with robust standards in relation to financial commitments to ensure that capacity providers that fail to meet key delivery milestones are sufficiently penalised. They argued that without this there will be no incentive to stop speculative developers participating and driving auction clearing prices down.

4.9.4 Other key points made included that:

- Defining a clear decision and appeal process for pre-qualification is important.
- There should be strict governance around the qualification criteria.
- RO auction bid volumes should be monitored to ensure they match qualification criteria, with this being a role that could be carried out by the independent NEMO as the independent auction administrator.
- The SEMC needs to give further consideration within the DS3 System Services and I-SEM workstream on how the competitions interact with one another, including around qualification.
- There have been many qualification arrangements employed under various schemes over the years and the requirements should draw upon the lessons learned from these arrangements
- That the RAs need to accommodate special cases and projects, such as Grid-Scale Pumped Storage where the characteristics of those projects differ significantly from conventional generation

4.9.5 One respondent agreed with the proposed qualification requirements for existing plant and also with qualification requirements proposed for new and refurbished plant, and but argued that for a fair and equitable outcome if the investment is material, then refurbished plant should be subject to the same financial commitment criteria as new plant.

4.9.6 One respondent described how it has no objection to posting a prudently sized refundable bond to participate in the auction, but large multi-million euro non-refundable auction fees were not acceptable to them. The respondent argued that a generator should be also able to demonstrate planning, environmental consents and a connection offer to participate in the auction.

SEM Committee Decision

4.9.7 The SEM Committee has decided to review the alignment of the qualification criteria for the CRM and for DS3 System Services.

Next step

4.9.8 The DS3 System Services project have issued a consultation paper on the qualification requirements for DS3 System Services auctions / regulated service provision, and the SEM Committee will consider consultation feedback on whether it is appropriate to use common criteria.

4.10 SUMMARY OF SEM COMMITTEE DECISIONS

Supported generators: Eligible to bid, subject to the same de-rating principles as will be applied to other capacity providers

Mandatory versus discretionary bidding: Dispatchable plant will need to bid within a tolerance band of the centrally determined de-rating factor for that plant, unless it declares that it will close before the end of the delivery period. Intermittent plant will need to submit qualification information saying how many MWs they are going to bid into the auction, but will have freedom to not participate.

Non-firm transmission access generators: Eligible to bid, subject to the same de-rating factors and RO difference payments as firm generators, but exempt from any requirements to bid in the CRM auction.

Treatment of DSUs: The SEM Committee will explore whether it is feasible to implement the approach of crediting DSUs with the value of reduced energy consumption, within the context of the ETA, but will apply a hybrid option if this approach is not feasible. Under the hybrid, DSUs will be exempt from RO difference payments, when the demand response is delivered, but must make RO payments if the response is not delivered.

De-rating factors:

- Central de-rating factors will be technology specific, but make allowance for the impact of plant size.
- Based on **marginal contribution** to meeting the capacity requirement
- **Not grandfathered**: The quantity of RO awarded to new plant will be fixed for the life of that RO; however, the RO holder carries the risk and benefit of changes to the underlying technology de-rating factors for all but the first year of that RO

Aggregators:

- Aggregators will be required to produce evidence of physical backing in order to enter the CRM auction. For existing capacity, this will include being able to show evidence of a PPA, covering the capacity delivery period.
- At the current time, the SEM Committee is **minded not to introduce any such minimum size requirements for direct CRM participants**, but will keep this minded-to position under review during the auction design and implementation.
- There will be no maximum limit for the size of renewables plant that can participate via an aggregator.
- The limit for non-renewables plant hat can participate via an aggregator will be the same 10MW de-minimis threshold that applies in the I-SEM ETA.

Qualification: The SEM Committee has decided to review the alignment of the qualification criteria for the CRM and for DS3 System Services

5. SUPPLIER ARRANGEMENTS

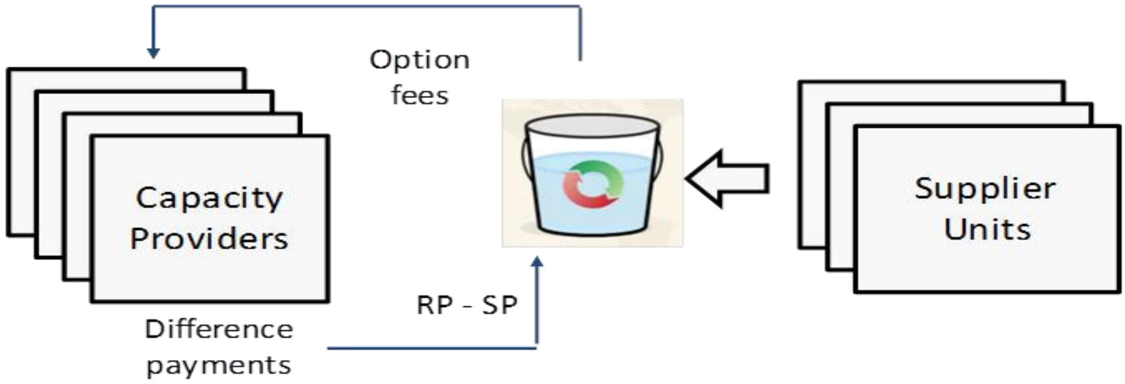
5.1 INTRODUCTION

5.1.1 The I-SEM Capacity Remuneration Mechanism (CRM) gives rise to a number of different cash flows between Suppliers and Capacity Providers. A diagram of the cash flows that results from this payment structure is shown below where a bucket represents the total pot of money to be recovered. The size of the pot for any 12 month commitment period will be equal to:

- The annual option fees;
- Less difference payments (RP-SP);

5.1.2 The latter two are unknown in advance, and may be volatile.

Figure 13: Key payment flows in the proposed I-SEM CRM



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5.1.3 For the Reliability Option to provide a hedge to Suppliers, difference payments will be allocated to Suppliers in proportion to the relevant demand of their customers during the Settlement Periods that gave rise to those difference payments. The remaining issues relate to:

- The allocation of option fees to Suppliers;
- The requirement for credit cover under the I-SEM CRM; and
- The treatment of exchange rate variations in the I-SEM CRM.

5.2 ALLOCATION OF OPTION FEES TO SUPPLIERS

Consultation Summary

5.2.1 The costs of the CRM will need to be recovered from Suppliers in proportion to some measure of the demand of their customers. There are two broad options for this measure of demand as follows:

- **Flat:** The charge is applied equally to all demand as a "per MWh" charge

- **Profiled:** The charge is focused on demand at times when there is likely to be system stress - and hence a reduced risk of scarcity.

5.2.2 Efficiency and equity suggest that a profiled approach should be used, as this focuses the costs of the CRM on that demand which drives the overall level of capacity that is required. There are a number of options for how a profile is established for the recovery of costs from Suppliers, with notable examples being:

- **The current SEM Approach - profiled across all hours**: Under the current SEM approach, the costs of capacity are allocated across demand at all times, but at a price which increases for times when incremental demand is likely to increase the need for capacity
- **GB (or similar) approach - focused on specific hours:** The costs of the GB CRM are allocated across that demand which occurs between 4pm and 7pm between November and February. This period is seen as broadly representing the time where an increment of demand would drive an increment to the level of capacity to be procured through the CRM. A similar approach could be adopted for Ireland, based on analysis of the times when incremental I-SEM demand is most likely to lead to a need for more capacity.

Summary of Responses Received

5.2.3 Response to the consultation that commented on this issue were varied in their view of the options, with each option attracting support. Key points arising from those responses against each option are as follows:

- **Focused:** Those supporting this option noted:

- It had the highest potential to generate efficient signals for customers to consume electricity at times that are consistent with minimising the overall costs of producing electricity; and
- It would need to be implemented flexibly, as the periods where capacity is most needed may change over time; and
- That the periods on which the charge is focused should be determined an advance, to allow Suppliers to incorporate an expectation of this charge into their tariffs.

- **Profiled:** Those that supported the profiled option argue that there is no reason to change from the arrangements currently used by the SEM, and highlight that it does provide some incentive on the appropriate timing of demand. One participant argued that this was the most equitable option
- **Flat:** Those that supported the flat option argue that it is not appropriate to incentivise load at a Settlement Period level whilst there are customers whose half hourly load is estimated based on a profile.

SEM Committee Response

5.2.4 The SEM Committee note that the pattern of demand for electricity is a major factor in determining the total quantity of capacity required. The efficiency of the I-SEM CRM is, therefore, enhanced by any changes to the pattern of demand that leads to a reduction in that need for capacity.

5.2.5 The fact that changes to the pattern of demand have the potential to reduce the overall costs of capacity argues for charges that for the fixed cost of capacity should be targeted at that demand which contributes most to the capacity requirement. In practice, this implies targeting the fixed costs in line with the Loss of Load Expectation[74] - suggesting either the “Focused” or “Profiled” approaches.

5.2.6 Analysis of the ex-post LoLP data as reported under the SEM shows a clear pattern of when demand is most likely to lead to an increase in the need for capacity, specifically, the periods between 1600 and 21:00 October to February, and between 08:00 and 21:00 March to September capture:

- 99% of top percentile LoLP;
- 90% of top 5 percentile of LoLP; and
- 85% of top decile of LoLP.

5.2.7 The SEM Committee note that some customers are not on interval (e.g. half-hourly) meters, and have their time of use estimated based on an assumed profile of demand. This use of profiles may mean that the Suppliers of profiled customers face a reduced incentive to encourage those customers to reduce demand at time of high LoLP; however:

- There is no reduction in the incentive in respect of customers that are on interval meters;
- The proportion of customers on interval meters will increase as and when smart meters are rolled out; and
- Suppliers of profiled customers are not disadvantaged vis-à-vis other such Suppliers by the use of the Focused or Profiled Approaches.

SEM Committee Decision

5.2.8 The SEM Committee have decided to adopt the focused approach, with the costs of capacity being recovered from Suppliers as a fixed €/MWh charge across demand in a pre-defined set of half hours that are judged to be those most likely to have high LoLP values. The specification of which half hours are used for this charging (the “Charging Base”) shall be kept under review by the SEM committee, acknowledging that the

[74] As the I-SEM CRM will purchase capacity based on a “Loss of Load Expectation” security standard, changing demand by 1MW at times when the Loss of Load Probability (LoLP) is high will impact the capacity requirement significantly more than changing demand by 1MW at times when LoLP is low.

pattern of LoLP may change over time. The initial Charging Base will be agreed by the SEM Committee no later than 6 months ahead of I-SEM go-live.

5.2.9 The SEM Committee recognise that the definition of the Charging Base will have an impact on customer tariffs, and will consider this impact in developing the Charging Base and in deciding an appropriate notice period for any change to that Charging Base.

5.2.10 As discussed in Section 4.6 above, the SEM Committee note that the allocation of option fees to Suppliers has a potential impact on energy storage. The SEM Committee note that those consuming electricity to be stored for later production of electricity would not be expected to do so at times of system stress. On this basis, such demand will not pay for the fixed costs of capacity.

Next Steps

5.2.11 The following next steps were identified:

- The initial Charging Base will be agreed by the SEM Committee no later than 6 months ahead of I-SEM go-live
- The SEM Committee will keep the Charging Base under review in light of potential changes to the pattern of LoLP.

5.3 CREDIT COVER LEVEL

Consultation Summary

5.3.1 It is typically assumed that all parties (principally Suppliers and capacity providers) will make the payments required of them under the terms and conditions. It is always possible that a party will default on their payment obligations, leading to a cash short-fall in the CRM. The risk of such a cash-shortfall can be (and typically is) reduced by requiring each party to provide credit cover that would be used to cover any shortfall in its payments.

5.3.2 In general, credit cover should be set at a level that would cover the maximum exposure to a defaulting party. This is consistent with the approach currently taken in determining levels of Supplier credit cover required under the Trading and Settlement Code.

Summary of Responses Received

5.3.3 A number of respondents favoured credit cover arrangements similar to those under the SEM. One respondent argued how it favoured the continuance of the provision that generator and supplier credit risk can be netted off and this should apply across all markets – capacity, energy, DS3 System Services. Another respondent described how the level of credit cover in the market should be set at a level that would cover the maximum exposure to a defaulting party.

5.3.4 A number of respondents favoured streamlining credit cover arrangements. One respondent described how netting of all credit arrangements should be performed wherever possible, with cross company netting across all work streams CRM, ETA and DS3 System Services. Another respondent stated that credit netting should be maximised in the I-SEM to minimise the amount and hence cost of collateral in the I-SEM.

5.3.5 A number of respondents favoured the cost of credit cover being minimised. One respondent described how credit cover costs should be minimised and would require consultation on the methodology used to calculate the quantum of credit to be lodged. This respondent argued that increased costs to new entrants for providing for credit cover facilities will be reflected in their bids. Another respondent stated that implementing excessive credit cover requirements for units generally in receipt of payments would not be equitable and would impose barriers to market access and entry for smaller participants.

SEM Committee Response

5.3.6 The SEM Committee agree both that:

- Credit cover should be set at a level that would cover the maximum exposure to a defaulting party (that party's indebtedness). This leads to a fair allocation of costs within the I-SEM – in line with the equity assessment criteria; and
- There are benefits in measures that would reduce the overall level of indebtedness that is considered for credit cover. This would improve the overall efficiency of the I-SEM – in line with the efficiency assessment criteria.

5.3.7 Respondents have mentioned "netting" as an approach to reduce the overall level of indebtedness that is considered for credit cover. This is an effective approach which is used elsewhere as a tool to manage credit risk. Where this is done, it is usually associated with "offsetting" which means that any payments to a defaulting party are reduced to reflect the level of default. Options for netting of credit cover requirements will be explored in the implementation phase.

5.3.8 The SEM Committee note that there are additional approaches that can reduce the level of indebtedness and hence the need for credit cover. A key such measure is to reduce the time between the physical flow of electricity (leading to liabilities to pay) and the actual payment for that electricity. We refer to this as the "delivery-to-cash" period.

5.3.9 The delivery to cash period for energy markets typically needs to be long enough to allow the data for the determination of payments (principally meter data) to be collected, verified, analysed and disputed. The SEM Committee notes that the data used for the settlement of the CRM is the same as that used of the settlement of the energy market, arguing that both could have the same delivery to cash period. Under the SEM, cash in respect of energy typically flows 9 working days after the end of the week during which the relevant electricity was delivered – giving a typical[75] delivery-to-cash period of between and 13 and 20 days after the physical flow of electricity, suggesting it is possible for payments arising from the I-SEM CRM to flow in similar timescales.

SEM Committee Decision

5.3.10 The SEM Committee has decided that the level of credit cover required from each party in respect of the I-SEM CRM should be based on that party's indebtedness. It further agrees that, where appropriate, measures should be taken to reduce the overall level of that indebtedness, notably:

- That the I-SEM should allow for offsetting of payments between the CRM and other I-SEM markets – provided that is feasible, and appropriate offsetting agreements can be established;
- That where offsetting is possible, a party's credit cover shall be determined based on the party's net indebtedness over those markets covered by offsetting; and
- That more consideration should be given to aligning the delivery-to-cash period for the I-SEM CRM with that for the I-SEM BM, and to the appropriate length of that period.

Next Steps

5.3.11 The following next steps were identified:

- Arrangements to support offsetting and hence reduce the level of required credit cover will be considered in the implementation phase.
- The appropriate length for the delivery-to-cash period will be considered in the implementation phase.

[75] Public holidays are not considered to be working days, meaning the period is occasionally longer

5.4 TREATMENT OF EXCHANGE RATE

Consultation Summary

5.4.1 There are two currencies within the I-SEM price zone. Ireland uses the Euro, whilst Northern Ireland uses the Pound Sterling. This introduces a risk that the exchange rate at the time payments are made will be different to that when the costs were incurred (i.e. at the time of the capacity auction, or of physical delivery).

5.4.2 The exchange rate issue exists in the current (SEM) market. However, the level of potential exchange rate exposure is much greater for capacity providers in the I-SEM than the SEM. The auctioned products will be much longer term, potentially up to fifteen years, whereas SEM capacity payments are set for one year only.

5.4.3 The SEM adopts the following solutions:

- **Capacity Payments:** The SEM includes capacity payments to be made to Generators, with the cost of these payments being recovered from Suppliers. The total level of these payments is determined ex-ante on an annual basis, and all payments are made based on a fixed exchange rate for the year. The market will face a gain or loss in respect of any exchange rate variations between the time the total level of payments was determined, and when the payments were made.
- **Energy Payments:** SEM Energy payments are determined in €, and converted to £ based on the exchange rate at the cut off time for bid submissions in respect of a trading day (EA1 Gate Closure). Actual payments happen at a later date, meaning that market will face a gain or loss in respect of any exchange rate variations between the relevant EA1 gate closure and the time of actual payments.

5.4.4 The cost arising from exchange rate variations has to be borne by the market in some way, with only two options:

- **Borne by market**: the exchange rates are fixed at the time participants commit (e.g. by submitting a binding bid). Any exchange rate gain or loss is then taken by the market operator (currently SEMO) and recovered as part of its costs. This is the approach used in the current SEM.
- **Borne by participant:** the market is priced, and makes payments, in one currency (e.g. €). Parties that incur costs in the other currency carry the cost of the exchange risk.

Summary of Responses Received

5.4.5 All respondents which commented on this area favoured the cost of exchange rate variations being socialised across the market, i.e. borne by the market. Respondents argued that given the dual currency nature of the I-SEM, it is appropriate to socialise the cost of exchange variations. It was argued that this is a fair, stable and efficient approach in a small market, and how this method also reduces barriers to entry for smaller participants.

5.4.6 One of these respondents suggested that the exchange rate for a capacity providers option fees could be fixed on an annual basis, meaning that providers with multi-year Reliability Options would still face exchange rate risk over the life of their contract.

SEM Committee Response

5.4.7 The choice of approach to the management of the exchange rate risk impacts the competition and efficiency assessment criteria, as discussed in the following paragraphs.

5.4.8 The option of having exchange rate variations borne by capacity providers would introduce an arbitrary distortion to **competition** between providers in Ireland and Northern Ireland, without necessarily reducing the cost of managing the currency risk. This distortion is arbitrary, as the choice of currency for the market is, itself, arbitrary:

- If the market is priced in £, Ireland participants will carry a cost of managing a currency risk, whilst Northern Ireland participants will not.
- If the market is priced in €, Northern Ireland participants will carry a cost of managing a currency risk, whilst participants in Ireland will not.

5.4.9 This distortion to competition would still exist if the exchange rate for capacity providers with multi-year contracts was only fixed on an annual basis, for each year of that contract.

5.4.10 The impact on the **efficiency** assessment criteria depends on whether the participant could manage the cost of the exchange rate risk at a lower cost than participants. In practice, currency forward markets are highly liquid – meaning that there should be little difference in the ability of the SEMO and Capacity Providers to hedge currency variations. As such, the impact on the “efficiency” assessment criteria is small, and the “competition” assessment criteria dominates.

SEM Committee Decision

5.4.11 The SEM Committee has decided that

- The exchange rate for option fees should be fixed at the time providers submit their bids to the capacity auction;
- The exchange rate for any difference payments should be fixed at the same time as it is fixed for the relevant energy market (e.g. at the time bids are submitted to the DAM).

Next Steps

5.4.12 Further consideration should be given to requiring the SEMO to lock-in the currency rate for option fees on an annual basis – to provide greater certainty over Supplier charges.

5.5 SUMMARY OF SEM COMMITTEE DECISIONS

5.5.1 The following box provides a summary of the SEM Committee Decision relating to Supplier Arrangements.

- **Allocation of Option Fees to Suppliers:** the costs of capacity will be recovered across demand in a pre-defined set of half hours that are judged to be those most likely to have high LoLP values. The specification of which half hours are used for this charging (the "Charging Base") shall be kept under review by the SEM committee, acknowledging that the pattern of LoLP may change over time.
- **Credit Cover:** the level of credit cover required from each party in respect of the I-SEM CRM should be based on that party's indebtedness. It further agrees that, where appropriate, measures should be taken to reduce the overall level of that indebtedness, notably:
  - That the I-SEM should allow for offsetting of payments between the CRM and other I-SEM markets – provided that is feasible, and appropriate offsetting agreements can be established;
  - That where offsetting is possible, a party's credit cover shall be determined based on the party's net indebtedness over those markets covered by offsetting; and
  - That more consideration should be given to aligning the delivery-to-cash period for the I-SEM CRM with that for the I-SEM BM, and to the appropriate length of that period.
- **Exchange Rate:** In relation to Exchange Rate, the SEM Committee has decided:
  - The exchange rate for option fees should be fixed at the time providers submit their bids to the capacity auction; and
  - The exchange rate for any difference payments should be fixed at the same time as it is fixed for the relevant energy market (e.g. at the time bids are submitted to the DAM).

6. INSTITUTIONAL FRAMEWORK

6.1 INTRODUCTION

6.1.1 The SEM Committee published a consultation Paper on 6 March 2015, I-SEM Roles and Responsibilities (SEM 15-016) setting out the proposed institutional arrangements and key roles and responsibilities for the establishment and operation of the I-SEM.

6.1.2 SEM-15-044 set out the SEM Committee's thinking on the overall governance for the I-SEM and how it will be based on overarching European regulations and guidelines and legislation in Ireland and Northern Ireland.

6.1.3 SEM-15-044 set out the intention that the new arrangements for the capacity mechanism will be implemented through market codes and other contracts. These detailed, codified rules will be underpinned as appropriate through existing or modified licence requirements in both jurisdictions.

6.1.4 In SEM-15-044, the SEM Committee consulted upon the following aspects of the institutional framework:

- **Roles and Responsibilities**: The planned assignment of roles and responsibilities for the administration of the new capacity mechanism including the capacity auction and settlement of capacity payments and charges. Consideration was also given to conflicts of interest and synergies regarding the proposed roles of the TSOs and market operator in the administration of the capacity mechanism and mitigation measures for any perceived conflicts such as business separation and market rules and audit requirements.
- **Capacity Market Rules and Codes:** Consideration of options for developing a system of codes and market rules and capacity agreements and counterparty arrangements for the new capacity mechanism.
- **Contractual Arrangements**: Consideration of options for contractual arrangements that would set out the rights and obligations of capacity providers who are successful in the capacity auctions. Two options were considered, 1. Contractual Counterparty (separate options model) and 2. Capacity Rules and Capacity Agreements (rules based model).
- **Implementation Agreements**: Consideration of whether an implementation agreement would be required and what relation such an agreement would have with the capacity market rules.

6.2 ROLES AND RESPONSIBILITIES

Consultation Summary

6.2.1 In SEM-15-044 the Roles and Responsibilities Section considered the following areas:

- Delivery and administration of the capacity market
- Settlement of capacity payments and charges
- Synergies and conflicts of interest

6.2.2 SEM-15-044 described how in our Roles and Responsibilities Paper (SEM 15-016) the change to a capacity mechanism which is based on a competitive bidding process requires a new set of roles and functions for the TSOs and/or market operator. While the SEM Committee will oversee the design of the capacity mechanism and its implementation through the approval of a set of capacity market and settlement rules, it will require a 'Delivery Body' to lead the implementation.

6.2.3 SEM-15-044 described the Capacity Market Delivery Role and suggested that the TSOs should carry out this role, which will include:

- **Setting the capacity requirement** (that is the amount to be auctioned based on a pre-defined security standard) including the de-rating of capacity providers as required;
- **Preparation, qualification and operation of auctions** as well as planning the auctions and publishing results;
- Provision to the body responsible for **settlement of data** and auction results necessary to settle capacity contracts and levy charges on market participants;
- **Test providers** to ensure those providers are able to demonstrate their capacity and validate eligibility of parties for secondary trading;
- Maintain a system or central register of **capacity agreements or take on contractual counterparty** to capacity contracts as appropriate.

6.2.4 SEM-15-044 sets out the SEM Committee's minded-to position that the market operator responsible for imbalance settlement in the new arrangements will also be responsible for the settlement of capacity payments and charges.

6.2.5 SEM-15-044 described how depending on the choice of design of the cross border capacity participation arrangements (will be set out in CRM Detailed Design Paper 2) there may be a need to address perceived or real conflicts of interest. Remedies suggested to deal with these potential issues included:

- **Clear transparent and audited rules**: Limit the extent to which the TSO has discretion in its delivery role (in particular in relation to the treatment of cross border capacity), and have independent assurance that it is performing its role objectively;
- **Business separation**: Some form of business separation between EWIC and the TSO's roles in the capacity market may be required. As a minimum, there is

likely to be a need for information separation - so that EWIC has no access (beyond that available to other capacity providers) to the information used in the delivery and settlement roles. The degree of business separation if required will be progressed by the RAs through the review of TSOs licences for implementation of I-SEM.

Summary of responses received

6.2.6 A number of respondents raised concerns around conflicts of interest for the TSO. These centred on Eirgrid's ownership of the East West Interconnector and how this could potentially impact the operation of the Capacity market, BM and DS3 System Services.

6.2.7 One respondent stated that for investor and consumer confidence, the administration of the CRM auction should be carried out by a suitably objective body, independent/ ring-fenced from the TSO. Another respondent stated that the TSO is probably best placed to be the delivery body for the capacity market but that the settlement process should be independent of the TSO. One respondent did not agree that TSO should be the delivery body for the I-SEM Capacity Mechanism and felt that this is the duty of the Regulatory Authorities.

6.2.8 A number of respondents suggested business separation as a solution, but one respondent stated this would be unlikely to provide reassurance to the market. A number of respondents suggested clear transparent and audited rules. It was suggested by one respondent that there could be independent verification of the EWIC de-rating subject to CER overview.

6.2.9 A number of respondents stated that outlined governance arrangements seemed suitable for implementing the I-SEM capacity mechanism.

6.2.10 One respondent supported the proposal that the market operator should carry out settlement of CRM. Another respondent stated that they saw no reason why the I-SEM should depart from international norms and have a body other than the TSO(s) as the Delivery Body.

6.2.11 One respondent stated that these potential conflicts of interest issues should be managed through the Roles and Responsibilities work stream.

SEM Committee Response

6.2.12 The SEM Committee is mindful of the need to strike the right balance between maximising synergies and mitigating measures for real or perceived conflicts of interest so that the long term interests of consumers are protected.

6.2.13 The I-SEM Roles and Responsibilities work stream (Consultation Paper SEM-15-016) considered both the synergies of one entity carrying out several of the operational roles for I-SEM such that transaction costs to market participants are minimised, and balanced this with concerns around real or perceived conflicts of interests that could lead to increased costs to consumers and mitigation measures that might be required to minimise such conflicts.

6.2.14 In the I-SEM Roles and Responsibilities Paper a number of mitigation measures were set out that could be applied to address conflicts of interest. Four main categories of mitigation measures were considered:

- Ring-fencing
- Behavioural
- Control/Responsibility
- Transparency

6.2.15 The I-SEM Roles and Responsibilities Paper set out a number of mitigation measures that could be applied to address conflicts of interest, including business separation or 'ring-fencing' requirements. These included:

- Information separation
- Employee and staff separation
- Physical separation
- Financial separation and additional financial obligations
- Legal separation

6.2.16 The SEM Committee decision through the I-SEM Roles and Responsibilities work stream was that the TSOs will be responsible for delivery of the Capacity Remuneration Mechanism including administration and qualification for the capacity auctions and administration of a set of capacity market rules subject to approval and oversight by the RAs.

6.2.17 The SEM Committee also decided that, in order to maximize synergies and lower transaction costs in I-SEM, SEMO will be responsible for the function of capacity mechanism settlement; this is consistent with the minded-to position provided in the consultation that the same entity would be responsible for settlement of imbalances.

6.2.18 As set out in SEM-15-044 the design of the cross border capacity participation arrangements will be set out in CRM Detailed Design Paper 2. As set out in SEM-15-044 there are a number of remedies that can be adopted if this conflict of interest is perceived to be an issue and if it is shown to raise costs to consumers.

SEM Committee Decision

6.2.19 The SEM Committee set out its decision on I-SEM Roles and Responsibilities in SEM 15-077. This provided that the TSOs will be responsible for the delivery of the Capacity Remuneration Mechanism including administration and qualification for the capacity auction as well as administration of a set of capacity market rules subject to approval and oversight by the RAs.

Next Steps

6.2.20 The detailed design of the governance arrangements will be progressed through the governance review process, as well as being considered in subsequent CRM decisions.

6.3 CAPACITY MARKET RULES AND CODES

Consultation Summary

6.3.1 SEM-15-044 in Capacity Market Rules and Codes Section considered the following areas:

- Capacity settlement rules
- Capacity market rules
- Capacity market agreement

6.3.2 SEM-15-044 described how the CRM includes a number of requirements that may require different governance arrangements. Areas specific to CRM that will need to be provided for in the all island legal framework include:

- The guidelines for delivery body in determining capacity requirement;
- The qualification requirements for participation in capacity auctions;
- The guidelines or rules for determining de-rating factors for capacity participants;
- The contract with the Delivery Body and Settlement Agent - including, in each case, how costs are approved and recovered;
- The rules for determining payments to be made under the CRM.

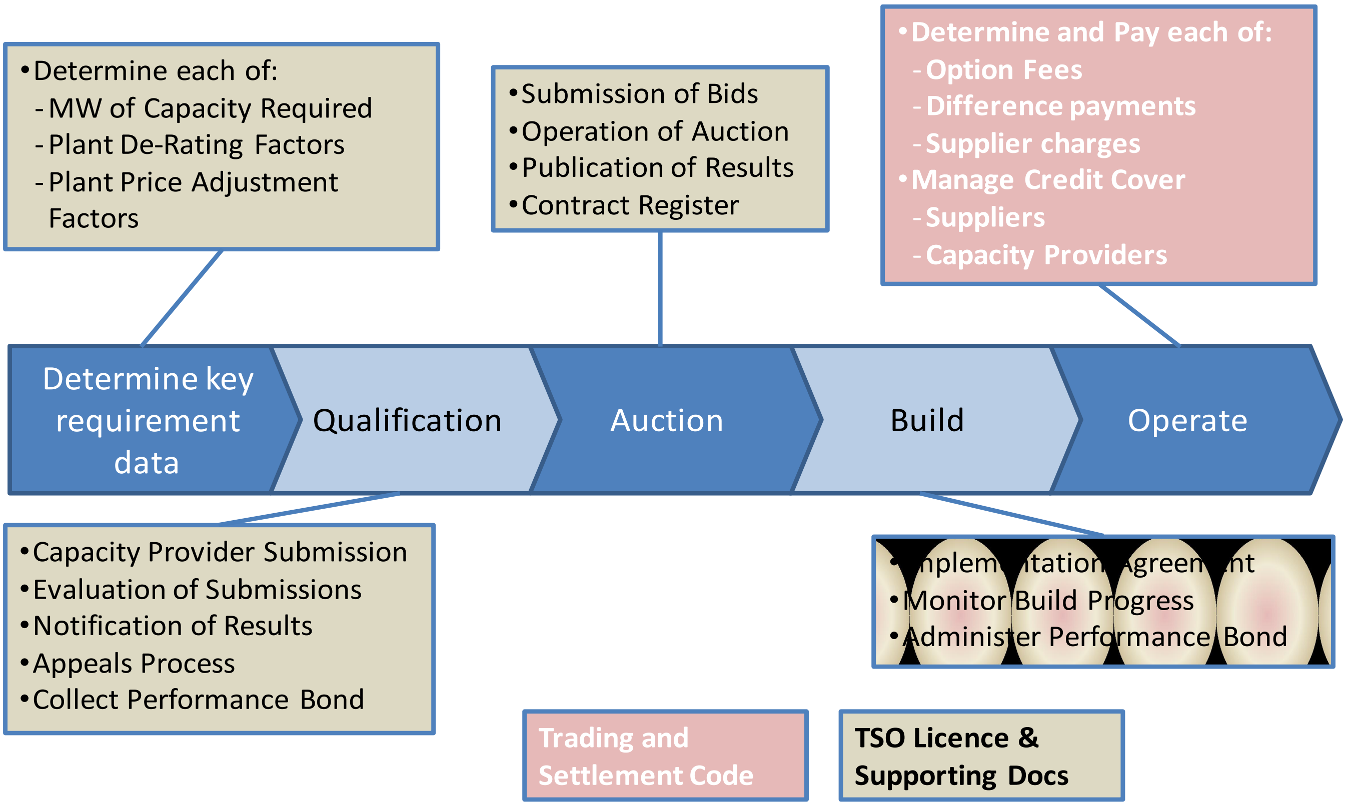
6.3.3 SEM-15-044 described how the new capacity mechanism will require an auction process where eligible capacity providers compete for contracts to provide the required capacity. This auction process will lead to a clearing price that will replace the current administrative process for the determination of the price. Successful participants in the auction will enter into a series of contractual commitments.

6.3.4 In order to implement the new arrangements the SEM Committee intends to develop a set of capacity market rules. These will set out the rules and procedures for participation in and qualification for the capacity auctions as well as potentially providing the framework under which the TSO enters into capacity agreements that set out the obligations and rights of market participants who have been successful in the capacity auctions.

6.3.5 SEM-15-044 described how Capacity Market Agreements will record the key parameters of the capacity agreement and how the Trading and Settlement Code will detail the payments to be determined and administered by the relevant market operator.

Error! Reference source not found. below illustrates the proposed governance arrangements for the new capacity mechanism:

Figure 14: Overview of proposed governance



Summary of responses received

6.3.6 A number of respondents stated that the CRM rules should, where possible all be encompassed within the revised Trading and Settlement Code to provide transparency and clarity for all participants and potential new entrants.

6.3.7 A number of respondents stated that the outlined governance arrangements seemed suitable.

6.3.8 One respondent was of the view that the governance arrangements for the capacity mechanism provide the right balance between the objective of stability, practicality and adaptability as described in Figure 6-3 of the CRM Detailed Design Consultation Paper.

6.3.9 One respondent stated that for investor certainty changes to RO terms and conditions should only be permitted where absolutely necessary.

SEM Committee Response

6.3.10 As set out in SEM-15-044 it is envisaged that the detailed rules for the remuneration of capacity providers and the associated rules for capacity charges on suppliers along with the pricing and settlement rules for the energy trading arrangements will be set out in the revised Trading and Settlement Code.

6.3.11 SEM-15-044 described the trade-off between the need for change and the need for stability when considering governance arrangements covering changes to the CRM terms and conditions. These two factors are resolved by creating a governance framework that constrains the ability of Government, Regulators and participants to change the terms and conditions.

SEM Committee Decision

6.3.12 The SEM Committee considers the proposed governance arrangements, including associated licence and code changes, as suitable. It is envisaged that the detailed rules for the remuneration of capacity providers and the associated rules for capacity charges on suppliers will be set out in the revised Trading and Settlement Code.

6.3.13 The SEM Committee will continue to monitor and consider these governance arrangements as further decisions are made during the subsequent CRM Detailed Design Papers 2 and 3, and other work streams.

Next Steps

6.3.14 Development of the detailed rules for the remuneration of capacity providers and the allocation of capacity costs and benefits to Suppliers will be considered in implementation.

6.3.15 The RAs will consider the impact of future CRM decisions on the governance arrangements.

6.4 CONTRACTUAL ARRANGEMENTS

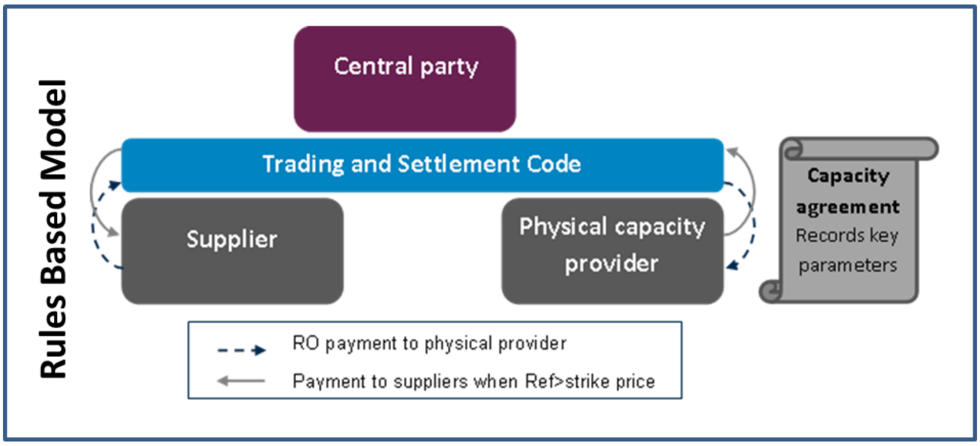
Consultation Summary

6.4.1 SEM-15-044 outlined that the issue of contracts lengths will be covered in the Capacity Mechanism Detailed Design Paper 2. This will look at the need to ensure fair competition between new and existing providers and the rationale for capacity contract lengths of greater than one year to allow new projects to access lower cost financing. Also conversely, there may be increased risk for consumers and reduced competition in future auctions from longer term contracts. The contractual arrangements Section of SEM-15-044 considered what arrangements may need to be put in place to allow for annual or multiannual capacity contracts.

6.4.2 SEM-15-044 considered three options for contractual arrangements, these were:

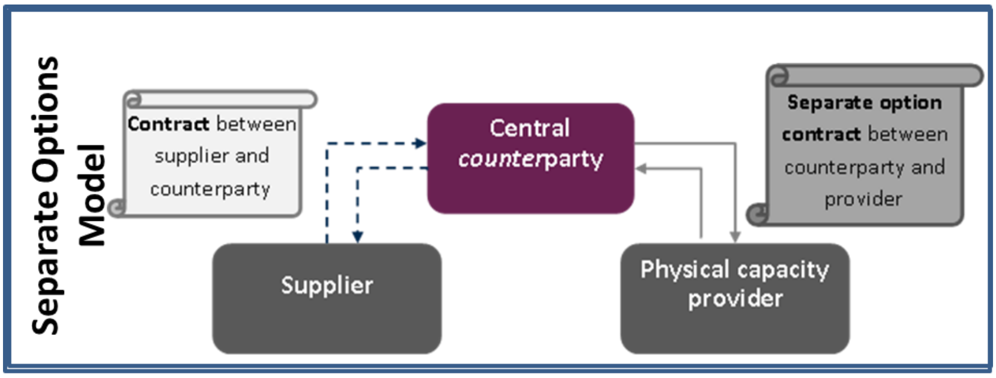
- **Rules based model** - whereby the central body is effectively arranging payment flows between the physical capacity providers and the suppliers. The flows and payments would be codified ex-ante (forming part of the market rules or licences). The central body takes more of an operation/oversight role and not a central counterparty role. This is illustrated in Figure 15 below[76]:

Figure 15: Overview of Rules Based Model



- **Separate option model** - whereby the central body purchases options directly from physical capacity providers through the CRM auction. This is similar to the current arrangements for the procurement of DS3 System Services, resulting in bilateral contracts between the Central Party and Capacity Providers (albeit the bulk of the contractual terms will be standardised). In one variant of this model the central body is also selling these options on to suppliers. Here the central body is acting as the central counterparty. This is illustrated in Figure 16 below:

Figure 16: Overview of Separate option model



- **Hybrid model** - generated by combining aspects of 1 and 2 that change the risk/exposure for the central body. For example, a separate options based approach could be used where the central body buys RO contracts from participants but the settlement arrangements between the central body and suppliers are codified and therefore rules based.

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[76] These "rules" may be captured in a contract or code (e.g. the Trading and Settlement Code)

6.4.3 SEM-15-044 asked which options for contractual arrangements are the most appropriate as assessed against the listed criteria?

Summary of responses received

6.4.4 The majority of respondents favoured the rules based model describing how it builds on the existing SEM arrangements and GB auction model. Respondents favoured this model as it provides certainty and transparency. Respondents described how it must be subject to robust and transparent governance arrangements. This model was also favoured by respondents as it is likely to be simpler to implement.

6.4.5 A number of respondents favoured the separate options model. Respondents choose this model due to the certainty it provides, reducing funding costs, especially relevant for new entrants with a requirement for a long-term capacity contract with certainty of payment. One respondent described how without a single counterparty body available to take on the liabilities created by allocated reliability options this could potentially have damaging impacts on the ability of the licence holders to finance their activities.

6.4.6 One respondent described how the rules-based model offers advantages in terms of adaptability and practicality, given that it will be simpler to administer and modify a single industry code rather than potentially hundreds of separate capacity contracts. It would not be necessary to draft, negotiate, enter into and manage multiple contracts with each market participant.

6.4.7 This respondent described how in relation to investors in new capacity the current SEM has attracted new entry under a rules-based capacity mechanism, as has the recently implemented GB capacity market (which also does not have a central counterparty). The respondent described how in the GB capacity market there are statutory obligations on suppliers to fund the capacity payments, and suppliers provide credit cover against their capacity payment obligations. Capacity payment defaults are socialised across remaining suppliers, thereby ensuring that capacity providers continue to be remunerated.

6.4.8 This respondent stated its understanding, based on legal advice received to date, is that the separate options model is more likely to impose requirements under financial legislation than the rules based model, compliance with such regulations creates complexity for both participants and the central party.

6.4.9 A number of respondents favoured the hybrid option model, as a way of solving the counterparty problem. One of these respondents described how new entrant investors face greater financial and long term risks than existing incumbents when entering a capacity market. Hence they will need an option contract to reduce investment risk and provide legally binding proof to financial investors of the terms and conditions of a bankable revenue stream.

6.4.10 One respondent described how in relation to long term contracts that as a proportion of the capacity requirement, they would expect that the percentage of long term contracted capacity would be well below 20%. This respondent also stated that long term contract concerns need to be carefully weighed against the benefits of valuable competition new entrants provide in the market.

6.4.11 A number of respondents saw merit in the different options but did not provide a preference.

SEM Committee Response

6.4.12 The choice of contract model represents a trade off between a number of the assessment criteria, notably:

- **Competition and Stability:** The SEM Committee recognises that the separate option counterparty model could provide a formal contract which, at first sight, provides greater certainty for investors, particularly where looking to enter into long-term capacity agreements. The issue is whether this increased certainty is material, and whether it is one of perception rather than an actual increase in certainty. In this context, the SEM Committee notes:

- That the GB Capacity Market is rules based – but has been successful in attracting new entrant capacity;
- That any bilateral RO would not necessarily increase stability, as the respective Governments and Regulators will need to retain the ability to impose change. This is also the case for the CfDs used to procure low-carbon generation in GB;
- The stability of contractual arrangements in a rules based model can be enhanced through the governance of those rules – for example through a set of principles against which changes to those rules must be assessed. This is the case for the existing Trading and Settlement Code, where any changes have to be consistent with the objectives for that code. Additional principles can be added if required.

- **Adaptive and Practical:** The rules based model is easier to adapt to changes in the sector, but can still provide protection to investors:

- The rules based model is the easier option to change if (for example) a change elsewhere in the I-SEM necessitated a change to how the ROs are settled. As mentioned above, the potential risk to investors of such changes can be significantly reduced through safeguards in the governance of the relevant rules (e.g. principles against which any change must be assessed)
- In the separate contract model, any changes to detailed contract terms would need to be agreed on a bilateral basis. This is likely to be a high cost process, with a significant risk that contracts end up different between participants. This, in turn, would increase the cost of operating the I-SEM.

6.4.13 In the rules-based approach the TSO maintains a set of auction rules and register of the agreements arising from each auction. Certainty for investors can be provided by making certain details entered in the register not subject to amendment. This could include characteristics such as the duration of the capacity agreement, the capacity cleared price, the relevant milestone date, the different penalty caps and the capacity obligation for which the capacity agreement is issued. The contract register is expected to contain information such as the following:

- Unique Entry ID – Unique identifier for participant which holds the Reliability Option
- Unit ID – Unique identifier for the unit which holds the Reliability Option
- Contracted Quantity - The MW capacity contracted as the Reliability Option
- De-rating factor – The de-rating factor applied to unit holding the Reliability Option
- Start/End Date – The date from which new/existing capacity is deemed to have been commissioned/de-commissioned
- Commissioning Date – Start date for existing plant and for new build plant day immediately following the end date, then set to the commissioning date
- Long Stop Date – The date by which new plant must be commissioned
- Strike Price – The €/MWh Strike Price arising from the relevant auction
- Option Fee - The €/MWh year fee paid for the Reliability Option
- Capacity - The MW capacity that has been commissioned. For plant that exists before it is awarded a capacity contract, this is set to its registered capacity.

6.4.14 Participants would be issued (under an agreed procedure) with the data held on the register in a form suitable for their financial institutions.

SEM Committee Decision

6.4.15 The SEM Committee decision is to use the Rules Based Model for the detailed contractual terms that cover the settlement of Reliability Options. Those detailed terms will be captured within a future Trading and Settlement Code, with the details of each Reliability Option being retained in a Contract Register to be maintained by the TSOs. The governance arrangements for the relevant parts of the Trading and Settlement Code as well as for the Contract Register should be developed to provide reasonable protection for the legitimate interests of investors in new capacity.

6.4.16 The “Capacity Market Rules” will form part of the TSOs’ licences – along with the specification of any other things they are required to do in their role as Delivery Body (albeit potentially as supporting documents to the licence). The Capacity Market Rules will cover:

- The operation of the Capacity Market Auction;
- Qualification for that Auction;
- Registration of contract arising from the auction; and
- Implementation agreements

Next Step

6.4.17 The detailed arrangements will be developed by the SEM Committee in conjunction with the TSOs

6.4.18 We will consider further how the governance arrangements should be developed to provide protection for the legitimate interests of investors in new capacity. This will include:

- Whether any additional principles (over and above the statutory duties of the RAs, and the T&SC objectives) are needed to protect investors;
- Whether any further measures are required.

6.5 IMPLEMENTATION AGREEMENT

Consultation Summary

6.5.1 SEM-15-044 described how mechanisms to procure new capacity typically include measures to manage the period between a capacity provider having its bid accepted, and the relevant capacity coming into operation (the build phase). This normally has two parts:

- **Performance Bond:** A performance bond that is provided at the outset by the bidder, and will be sacrificed in certain defined circumstances (e.g. if the project is abandoned); and
- **Implementation Agreement:** An agreement that allows the Delivery Body to monitor progress in building the capacity.

6.5.2 SEM-15-044 described how implementation agreements should be based around a number of defined milestones, with the developer losing some or all of its performance bond if those milestones are missed. Ideally the nature and timing of these milestones is negotiated between the buyer and developer; however this is difficult to achieve in capacity markets - where the buyer is acting as an agent of the sector. In this situation, it is more normal to define each of the:

- Nature of the milestones;
- Time bounds for achievement of the milestone; and
- Extent to which the performance bond is at risk on those milestones.

6.5.3 This tends to drive to milestones that will be common across all capacity development costs, notably:

- **Substantial Financial Commitment**: When the developer has financially committed to the actual project. This can be measured in a number of ways, but is typically expected to occur relatively quickly following the award of the capacity contract.

- **Substantial Completion**: When the relevant capacity is performing at or near the level specified in its capacity contract. There is typically a window of time during which this milestone can be met, with a capacity provider's contract being scaled back to the level of capacity it has managed to demonstrate at the end of that window.

6.5.4 SEM-15-044 described how for the I-SEM CRM, the following would need to be considered:

- Whether any milestones in addition to "financial commitment" and "substantial completion" milestones are required;
- How each milestone should be measured;
- What is an acceptable time window for demonstrating each milestone has been met;
- The consequences of failing to meet a milestone.

6.5.5 SEM-15-044 asked are implementation agreements required for new entrants participating in the capacity auctions?

Summary of responses received

6.5.6 The majority of respondents agreed that implementation agreements were required for new entrants. Respondents stated these were required to provide a strong incentive to ensure that new builds deliver the physical capacity if they win a RO contract in the auction. A number of respondents described that these should be strictly enforced with a level of penalty exposure to dissuade non readiness. One respondent described how some consideration should also be given to potential delays that are unambiguously beyond the developer's control.

6.5.7 A number of respondents stated that having onerous performance bonds would be a barrier to new entry of capacity. One of these respondents described how if such a bond were required, an implementation agreement would be appropriate to govern its administration, reduction and cancelation. One respondent stated it had no objection to posting a prudently sized refundable bond to participate in the auction, but large multi-million euro non-refundable auction fees would not be acceptable.

6.5.8 One respondent described how the generator must be also able to demonstrate planning, environmental consents and a connection offer to participate in the auction.

SEM Committee Response

6.5.9 Whether or not Implementation Agreements and Performance Bonds are required represents a trade off between the "Security of Supply" and the "Competition" assessment criteria as follows:

- **Security of Supply:** Where an auction results in the award of an RO to a new-entrant, that new-entrant is required to maintain security of supply consistent with the relevant security standard. Should that project fail, it will need to be replaced to ensure that security of supply is maintained at an acceptable level. As this replacement may not be immediate, the failure of a project is likely to result in a period where the actual security of supply in the I-SEM is less the security standard

- **Competition:** As highlighted by a number of respondents, the provision of security cover is a cost to the new entrant. This cost may act to restrict entry.

6.5.10 Recent experience from the GB Capacity Market highlights the potential risks of new-build projects to security of supply. A number of projects have failed to make financial close, meaning the GB system will potentially have less capacity than it required. This has led the UK Government to consult on increasing the assurance provided by Performance Bonds and Implementation Agreements[77], notably:

- Requiring evidence of committed financing at the qualification stage;
- Increasing the number of milestones with the addition of seven (bidder nominated) project milestones;
- Increasing the frequency of project reporting leading up to financial close; and
- Increasing the level of bond (and the eventual penalty) as evidence builds that a project may slip or be abandoned.

6.5.11 The SEM Committee is cognisant of the trade-off in setting the level of the performance bond. As stated by a number of respondents having onerous performance bonds could be a barrier to new entry of capacity. However setting the level of performance bonds too low could weaken the incentive to ensure that new builds deliver the physical capacity if they win a RO contract in the auction.

SEM Committee Decision

6.5.12 The SEM Committee has decided that Implementation Agreements are required. These Implementation Agreements will be based around a number of defined milestones. These milestone shall include:

- Substantial Financial Commitment
- Commencement of Construction
- Substantial Completion
- A number of additional project milestones to be defined by the bidder

Next Steps

6.5.13 The detailed design of implementation agreements will be considered as part of the CRM Consultation 2.

[77] See DECC Consultation Paper -15D/457 “Consultation on reforms to the Capacity Market”, 15 October 2015

6.6 SUMMARY OF SEM COMMITTEE DECISIONS

6.6.1 The following box provides a summary of the SEM Committee Decision relating to the Institutional Arrangements.

- **Roles and Responsibilities:** The SEM Committee set out its decision on I-SEM Roles and Responsibilities in SEM 15-077. This provided that the TSOs will be responsible for the delivery of the Capacity Remuneration Mechanism including administration and prequalification for the capacity auction as well as administration of a set of capacity market rules subject to approval and oversight by the RAs.
- **Rules and Codes:** the proposed governance arrangements, including associated licence and code changes, are suitable. It is envisaged that the detailed rules for the remuneration of capacity providers and the associated rules for capacity charges on suppliers will be set out in the revised Trading and Settlement Code. The SEM Committee will continue to monitor and consider these governance arrangements as further decisions are made during the subsequent CRM Detailed Design Papers 2 and 3, and other work streams.
- **Contractual Arrangements:** Reliability Options will be Rules Based rather than bi-lateral contracts. The governance arrangements for these rules should be developed to provide reasonable protection for the legitimate interests of investors in new capacity.
- **Implementation Agreement:** Implementation Agreements are required for developers of new capacity. These Implementation Agreements will be based around a number of defined milestones – including a number of specific milestones specified in the decision above.

7. NEXT STEPS

7.1.1 A number of “next steps” have been identified associated with the decisions set out in this paper. These next steps fall into the following areas:

- **System Modelling:** There are a number of areas where more work is required to develop analytical methodologies that will impact the quantities of Capacity that are procured through the Reliability Options. This relates to the approach to determine plant de-rating factors, and that to determine the overall capacity requirement. In each case:

- The TSOs will be asked to lead the development of these analytical methods;
- The RAs will separately consult on the methodologies, based on the work done by the TSOs.

- **Parameters:** A number of decisions in this paper are subject to specific parameters that will be set (and kept under review) by the SEM Committee. Many of these will be considered as part of CRM Consultation 2; The key such parameters are:

- The parameters that determine the ASP – which will be considered as part of Consultation 2;
- The detailed arrangements for the socialisation of any shortfall in RO difference payments. This is expected to be considered as part of CRM Consultation 3;
- The parameters for the Strike Price. These will be consulted on and finalised in advance of the start of qualification for the first capacity Auction.
- The Maximum Exit Price (for the Capacity Auction) will be considered further as part of CRM Consultation 3;
- The level of the “stop loss” limit. The principle for this will be considered as part of CRM Consultation 2, with the actual value being kept under review and determined in time for the start of qualification;
- The Charging Base for the Supplier charging for the costs of capacity will be finalised by six months ahead of I-SEM go-live.; this will be preceded by a separate consultation process.
- The actual level of charges to Suppliers will be published as soon as is reasonably practicable following the first Capacity Auction. .

- **Detailed Settlement Rules:** Detailed rules for the Settlement of Reliability Options are under development, and will be progressed through the I-SEM Rules Working Groups from early 2016.
- **Governance and Licensing:** The changes to licences and associated documents to give effect to the CRM will be progressed as part of the Governance Review Framework.

APPENDIX A. ACRONYMS

ACER	Agency for the Co-operation of Energy Regulators
ACPS	Annual Capacity Payment Sum
AER	Alternative Energy Requirement
ALFCO	Adjusted Load Following Capacity Obligation
ASP	Administered Scarcity Price
BCoP	Bidding Code of Practice
BM	Balancing Market
BNE	Best New Entrant
CACM	Capacity Allocation and Congestion Management
CCGT	Combined Cycle Gas Turbine
CfD	Contracts for Difference
CMU	Capacity Market Unit
CRM	Capacity Remuneration Mechanism
DAM	Day Ahead Market
DCENR	Department of Communications, Energy and Natural Resources
DECC	Department of Energy and Climate Change
DSR	Demand Side Response
DSU	Demand Side Unit
EC	European Commission
EEAG	The Environmental and Energy State Aid Guidelines
ENTSO-E	European Network of Transmission System Operators - Electricity
ETA	Energy Trading Arrangements
EU	European Union
FiT	Feed in Tariff
FOR	Forced Outage Rate
FTR	Financial Transmission Right
GB	Great Britain
GB CM	Great Britain Capacity Market
GDP	Gross Domestic Product
GTUoS	Generator Transmission Use of System

GUA	Generating Unit Agreement
HLD	High Level Design
ICE	Intercontinental Exchange
IDM	Intra-Day Market
IED	Industrial Emissions Directive
I-SEM	Integrated Single Electricity Market
ISO NE	Independent System Operator New England
LoLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MB	Balancing Market (Italy)
MGP	Day Ahead Market (Italy)
MRP	Market Reference Price
MSD	Ancillary Services Market (Italy)
MW	Megawatt
MWh	Megawatt hour
NG	National Grid
OCGT	Open Cycle Gas Turbine
ODR	Over Delivery Rate
PER	Peak Energy Rents
PFP	Pay-for-Performance
PJM	Pennsylvania Jersey Maryland
PPA	Power Purchase Agreement
PPB	Power Procurement Business
PSO	Public Service Obligation
ROC	Renewables Obligation Certificate
RP	Reference Price
SEM	Single Electricity Market
SEMC	Single Electricity Market Committee
SO	System Operator
SoLR	Supplier of Last Resort
SP	Strike Price
SRMC	Short Run Marginal Cost
TLAF	Transmission Loss Adjustment Factor

TSC	Trading and Settlement Code
TSO	Transmission System Operator
US	United States
VoLL	Value of Lost Load

APPENDIX B. WORKED EXAMPLES OF MARKET REFERENCE PRICE OPTION 4B

In this Appendix we provide worked examples to illustrate how the Reliability Option based upon Market Reference Price option 4b will work. These examples are provided in response to request for more examples and detail from consultation respondents. Specifically:

- Example 1 explains in more detail how Option 4b will work, and compares it to Option 3;
- Example 2 shows how Option 4b works in conjunction with two-way CfDs;

For simplicity Examples 1 and 2 have ignored intra-day volumes, but Example 3 illustrates the planned treatment of intra-day volume as well.

Worked example 1

In Example 1 above, let us assume that the TSO has estimated that to meet the capacity requirement, 280MW of capacity is required.

Let us assume that the Strike Price for the RO is €500/MWh.

This requirement has been met by contracting four generators, each with 100MW nameplate capacity. A, B and C are thermal baseload, mid-merit and peak thermal generators respectively, and each is de-rated to 90% of nameplate capacity, and each has acquired a 90MW RO. Generator D is a 100MW wind generator, de-rated to 10% of nameplate capacity, with 10 MW of RO, so that the total de-rated and contracted capacity is 280MW.

Generator C, however, is an unreliable generator, whose strategy is to earn capacity payments and gamble that scarcity never occurs.

Now let us further assume that for Settlement Period t, at Day Ahead stage:

- It is anticipated that total demand on the system will be 200MW, with Supplier E forecasting a demand of 100MW for its customers, and Supplier F also forecasting a demand of 100MW for its customers. Let us assume that both Supplier E and F procure this forecast demand in DAM;
- It is anticipated that there will be 30MW of wind output, so Generator D sells 30MW of output, and the rest of the 200MW is filled in merit order, with 100MW of sales by A, and 70MW by B;
- There are no known outages expected (nobody except C knows that Generator C cannot really deliver on capacity), so spare capacity exists and the market clears at €100/MWh.

Example 1 – Settlement of RO under Option 4b compared to Option3

Assumptions

RO Strike Price	500
Day Ahead Market Price	100
BM price	10000

Capacity provider	Nameplate	ROQ	EAQ	MQ
A (thermal baseload)	100	90	100	100
B (thermal mid-merit)	100	90	70	100
C (thermal peaker)	100	90	0	0
D (wind)	100	10	30	30
Total	400	280	200	230

Supplier		Deemed ROQ	EAQ	MQ
E		100	100	100
F		130	100	130
Total		230	200	230

Generator payment: Option 4b

	Ex ante trades	BM payments	RO diff payments	Total
A	€10,000	€0	€0	€10,000
B	€7,000	€300,000	-€156,071	€150,929
C	€0	€0	-€702,321	-€702,321
D	€3,000	€0	€0	€3,000
Total	€20,000	€300,000	-€858,393	-€538,393

Supplier payment: Option 4b

	Ex ante trades	BM payments	RO diff payments	Total
E	-€10,000	€0	€0	-€10,000
F	-€10,000	-€300,000	€285,000	-€25,000
Total	-€20,000	-€300,000	€285,000	-€35,000

Gen load following adj	82%
Supplier load following adj	1

Generator payment: Option 3 (DAM)

	Ex ante trades	BM payments	RO diff payments	Total
A	€10,000	€0	€0	€10,000
B	€7,000	€300,000	€0	€307,000
C	€0	€0	€0	€0
D	€3,000	€0	€0	€3,000
Total	€20,000	€300,000	€0	€320,000

Supplier payment: Option 3 (DAM)

	Ex ante trades	BM payments	RO diff payments	Total
E	-€10,000	€0	€0	-€10,000
F	-€10,000	-€300,000	€0	-€310,000
Total	-€20,000	-€300,000	€0	-€320,000

Now let us assume that after Gate Closure for Settlement Period t:

- Demand outturns higher, as a result of an increase in demand from Supplier F's customers.
- Generator B is now called to produce its full 100MW, with the TSO accepting an offer of 30MW in the BM.
- The TSO now calls on Generator C to start, at which point it becomes clear that Generator C cannot deliver on any of its supposed capacity
- Supplier F's demand rises to 130MW, at which point no further increases in demand can be served and scarcity occurs, so the price rises to the administratively set price of €10,000/MWh. Note that in this simplified example, we have ignored operating reserve.
- Note that in this example, scarcity occurs at 230MW of demand, whereas there is 280MW of Reliability Options so a load following factor of 230/280 = 82% is applied to generator difference payments

Now contrast the following results under Options 3 and 4b:

- Generator C avoids any penalties under Option 3, as it did not sell any volume in the DAM, so is not exposed to the scarcity price in the BM. Because the scarcity price only happens after day-ahead stage, it does not have to make any difference payments under the RO. **Under Option 3, it has not been penalised for its strategy of accepting capacity payments during times of non-scarcity, and hoping that it will not be called. By contrast, under Option 4b, Generator C is heavily penalised for failing to deliver its RO capacity in the BM**.
- **Under Option 3, Supplier F is heavily exposed** to the scarcity price (even though demand is significantly less than peak demand) as a result of Generator C's inability to deliver its RO capacity commitment. It faces the full scarcity price of €10,000/MWh on the 30MW unexpected increase in its customers' demand that it procured after Day Ahead stage, costing it €300,000. **However, under Option 4b, it gets €285,000 back via RO difference payments, capping its exposure at €500/MWh on its imbalance volume**. Whilst this is by no means a perfect hedge (nor should it be), it may prevent Supplier F from becoming insolvent.

The full calculation of each payment under Option 4b is set out in the table below.

	Ex ante trades (Day Ahead Market)	BM payment	RO payments
Generator A	100MW of EAQ sold x 1hr x €100/MWh (DAM price)	None-all volume sold in DAM	None since all 90MW of RO sold in DAM, at €100/MWh, i.e. less than Strike Price
Generator B	100MW of EAQ sold x 1hr x €100/MWh (DAM price)	30MW (MQ-EAQ) sold x 1hr x ASP of €10,000/MWh	None on 20MW of RO sold in DAM. Remaining 20MW of RO cashed out at 20MW x 1hr x (ASP of 10,000 – Strike Price of 100) x load following factor of 230/280
Generator C	No sales	None- does not make BM offer as not available	All 90MW of RO cashed out at BM price = 90MW x 1 hr x (ASP of 10,000 – Strike Price of 100) x load following factor of 230/280
Generator D	30MW of EAQ sold x 1hr x €100/MWh (DAM price)	None since MQ=EAQ	None since all 10MW of RO sold in DAM
Supplier E	100MW of EAQ bought x 1hr x €100/MWh (DAM price)	None since MQ=EAQ	None since all 100MW of demand bought in DAM at below Strike Price
Supplier F	100MW of EAQ bought x 1hr x €100/MWh (DAM price)	30MW of (MQ-EAQ) bought x 1hr x ASP of €10,000/MWh	None on 100MW volume secured in DAM. Receives payment of (€10,000 - €500)/MWh on 30MW x1 hr cashed out in BM

Worked example 2: with CfDs

Some of the respondents also expressed concern about the complexity of the interaction of the RO with existing forward hedging instruments, and the impact on liquidity in forward markets.

Whilst changes will be needed to the existing two-way CfD contracts to accommodate ROs, the benefits of forward hedging via two-way CfDs can be maintained, and ROs need not adversely affect forward market liquidity. The RAs note that forward market liquidity in the SEM is much lower than in many other European energy markets, an issue which the RAs may seek to address in the I-SEM, independent of the introduction of Reliability Options. The RAs will consult further on forward market liquidity in the context of the Forwards and Liquidity workstream.

The following worked example illustrates how relatively simple changes to two-way CfDs can be made, which maintain the hedging benefits of two-way CfDs, working in conjunction with Option 4b. In the following example, the two-way CfDs are referenced to the DAM price, but only payout up to €500/MWh, the assumed RO Strike Price.

Example 2 - Settlement of RO and two-way CfDs under Option 4b: Scarcity only in the BM

Assumptions

RO Strike Price	500	EAP (Day Ahead Price)	100
2 way CfD Strike Price	80	IMBP	10000

Capacity provider	Nameplate	ROQ	2 way CfD	EAQ	MQ
A (thermal baseload)	100	90	90	100	50
B (thermal mid-merit)	100	90	90	100	100
C (thermal peaker)	100	90	20	10	100
D (wind)	100	10		30	30
Total	400	280	200	240	280

Supplier		Deemed ROQ	2 way CfD	EAQ	MQ
E		140	100	120	140
F		140	100	120	140
Total		280	200	240	280

Generator payment (without RO)

	Day Ahead trades	BM payments	Old 2 way CfD	Total without RO
A	€10,000	-€500,000	-€1,800	-€491,800
B	€10,000	€0	-€1,800	€8,200
C	€1,000	€900,000	-€400	€900,600
D	€3,000	€0	€0	€3,000
Total	€24,000	€400,000	-€4,000	€420,000

Generator payment (with RO under Option 4b)

Day Ahead trades	BM payments	New 2 way CfD	RO diff payments	Total with RO
€10,000	-€500,000	-€1,800	€0	-€491,800
€10,000	€0	-€1,800	€0	€8,200
€1,000	€900,000	-€400	-€760,000	€140,600
€3,000	€0	€0	€0	€3,000
€24,000	€400,000	-€4,000	-€760,000	-€340,000

Supplier payment (without RO)

	Day Ahead trades	BM payments	Old 2 way CfD	Total without RO
E	-€12,000	-€200,000	€2,000	-€210,000
F	-€12,000	-€200,000	€2,000	-€210,000
Total	-€24,000	-€400,000	€4,000	-€420,000

Supplier payment (with RO under Option 4b)

Day Ahead trades	BM payments	New 2 way CfD	RO diff payments	Total with RO
-€12,000	-€200,000	€2,000	€190,000	-€20,000
-€12,000	-€200,000	€2,000	€190,000	-€20,000
-€24,000	-€400,000	€4,000	€380,000	-€40,000

In Example 2, let us assume that we have the same four generators and two suppliers as in the previous example. We assume that:

- As before, the generators have sold 280 MW of ROs, reflecting an expectation of peak demand, at a Strike Price of €500/MWh;
- Generators hedge forward 200MW using two way CfDs, reflecting a forward expectation of average demand. The two-way CfDs have a Strike Price of €80/MWh, reflecting an average expectation of the DAM price, with Generators A and B selling 90MW of CfD (the same volume as their de-rated capacity and RO volume), whereas the peak generator, C, sells 20MW of CfD. The wind generator does not sell forward any CfD volume;
- For Settlement Period t, at the Day Ahead stage:

- The expected demand is 240MW, above the above expected average demand of 200MW but below 280MW peak demand;
- There are no expected outages, and wind output is expected to be 30MW, so there is no scarcity;
- The DAM price is expected to be €100/MWh.

- However, in real time:

- Demand outturns at peak demand of 280MW, 40MW higher than forecast at the Day Ahead stage;
- The thermal baseload generator, A, has a partial outage of 50MW, so produces only 50MW, so there is only 280 MW of available generation, and scarcity occurs;
- The BM price rise to the scarcity price of €10,000/MWh.

As illustrated in Example 2, the net income of Generators A and B, the baseload and mid-merit generator generators, is the same in a model where there are no ROs (the middle panel coloured yellow) as it would be in a model with ROs (the right hand panel coloured, green). Generator D's income is also the same in the model without an RO and the model with an RO.

The only difference to generator income between the two models is that Generator C pays out a difference payment of €760,000 on its RO, which caps its BM revenue at €500/MWh, so that its net BM revenue is only €140,000[78] instead of €900,000 after RO difference payments. Some of this revenue is used to hedge the BM exposure of Suppliers E and F on their imbalance volumes of 20MWh each. **Therefore in this example a key benefit of the RO with Option 4b is that it has reduced the losses of Supplier E and F from €210,000 each to €20,000 each**.

Note however that in Example 2 no generator has been adversely affected by contracting forward with the new CfDs[79] in this example:

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[78] 80 MWh of energy sold within the RO into the BM x €500/MWh + 10 MW of de-rated capacity x €10,000MWh

[79] i.e. a CfD which does not payout above the RO Strike Price, as opposed to two-way CfDs in the SEM which payout across the full range of SEM prices

- Generators A, B and D have exactly the same net revenue with and without the RO
- Generator C has had its BM revenue capped, but its two-way CfD payment is the same in the model with an RO and without an RO[80].

Worked example 3: With Intra-Day Market included

In Example 3, we include a worked example, which shows how Option 4b would work, including the intra-day market in the example for completeness.

In this example, let us assume that the TSO has estimated that to meet the capacity requirement, 280MW of capacity is required. Let us assume that the Strike Price for the Reliability Option is €500/MWh.

This requirement has been met by contracting four generators, each with 100MW nameplate capacity. A, B and C are thermal baseload, mid-merit and peak generators respectively, and each is de-rated to 90% of nameplate capacity. Generator D is a wind generator, de-rated to 10% of nameplate capacity, so that the total de-rated and contracted capacity is 280MW.

[80] €400 = 20MW x (€100 Strike Price - €80 Day Ahead Market price)

Example 3 – Settlement of RO under Option 4b with Intra Day Market

Assumptions

Energy market and CRM settlement under Option 4b

RO Strike Price 500

							Energy				Reliability Option			
Capacity provider	Nameplate	ROQ	DAM sales	IDM sales	Meter Quantity	BM imbalance	DAM revenue	IDM revenue	BM revenue	Total	DAM volume	IDM volume	BM volume	Total payment
A (thermal baseload)	100	90	100	0	50	-50	10,000	-	- 500,000	- 490,000	90	0	0	-
B (thermal mid-merit)	100	90	90	10	100	0	9,000	1,200	-	10,200	90	0	0	-
C (thermal peak)	100	90	0	0	100	100	-	-	1,000,000	1,000,000	0	0	90	- 855,000
D (wind)	100	10	50	0	30	-20	5,000	-	- 200,000	- 195,000	10	0	0	-
Total	400	280	240	10	280	30	24,000	1,200	300,000	325,200	190	-	90	- 855,000

							Energy				Reliability Option			
Supplier		Deemed ROQ	DAM purchases	IDM purchases	MQ	BM imbalance	DAM costs	IDM costs	BM costs	Total costs	DAM volume	IDM volume	BM volume	Total
E		-120	-120	0	-120	0	- 12,000	-	-	- 12,000	-120	0	0	-
F		-160	-120	-10	-160	-30	- 12,000	- 1,200	- 300,000	- 313,200	-120	-10	-30	285,000
Total		-280	-240	-10	-280	-30	- 24,000	- 1,200	- 300,000	- 325,200	- 240	- 10	- 30	285,000

	DAM	IDM		BM
Market price	100	120		10000
RO unit difference payment	0	0		9500

Now let us further assume that for Settlement Period t, at Day Ahead stage:

- It is anticipated that total demand on the system will be 240MW, with Supplier E forecasting a demand of 120MW for its customers, and Supplier F also forecasting a demand of 120MW for its customers. Let us assume that both Supplier E and F procure this forecast demand in DAM;
- It is anticipated that there will be 50MW of wind output, so Generator D sells 50MW of output, and the rest of the 240MW is filled in merit order, with 100MW of sales by A, and 90MW by B;
- There are no outages expected, so spare capacity exists and the market clears at €100/MWh.

Assume that in the intra-day period Supplier F slightly increases its demand forecast and buys another 10MW from Generator B, but Generator C is not required, and the price rise marginal to €120/MWh.

Now let us assume that within an hour of the start of Settlement Period D:

- Demand outturns higher at 280MW
- Generator A has a partial outage of 50MW, so can only produce 50MW of its 100MW and has an imbalance of 50MW cashed out in the BM;
- The wind drops from an expected 50MW output to 30MW output, leaving Generator D 20MW short in the BM;
- Generator B produces its full nameplate capacity and is in balance;
- Generator C has to deliver its full output, and even then we run into scarcity conditions, so the BM price rise to a notional scarcity price of €10,000/MWh

Now, the following resulting payments are noteworthy:

- Generator A receives a total of €10,000 (100 x 100MWh) for its Day Ahead sales, but is hit by a charge of €500,000 (€10,000 BM price x 50MWh imbalance) resulting from its partial outage. However, because it has sold all of its 90MW Reliability Option volume in the DAM, all of its RO volume is settled at the DAM price of €100/MWh instead of the BM price €10,000. Therefore it is not further penalised under RO- as it appears some respondents feared. The incentive to stay available in this case is the high cost of being cashed out at the scarcity price in the BM.
- Generator B, which sold all of 90 MW RO volume in the DAM is not cashed out at the BM price either;
- Generator C, the peaking plant, which only sold in the BM, receives the €10,000/MWh scarcity price via the BM, but has the value in excess of the Strike Price of €500/MWh taken away from it on its 90MW RO volume, because it did not sell its capacity into the DAM.
- Part of this RO difference payment is used to cap Supplier F’s 30MW imbalance exposure at €500/MWh,

- The is an RO difference payment surplus, since Generator C's difference payments are only used to cap Suppliers' exposure to scarcity prices, and are not used to cap a Generator's exposure to scarcity prices resulting from its own outages.

This example illustrates a number of incentives properties/ features of the design, which are worth emphasising:

- Those generators who have sold forward in the DAM are not impacted by the RO, but do face the marginal cost of their actions in the energy market. There is no disincentive to sell into the DAM resulting from the RO- it is the energy market consequences of failing to honour their DAM sales that are expensive;
- If the marginal impact of their outage is load shedding, it is right that they should face this scarcity price;
- The impact of the RO has been to cap Generator C's gain if it is able to exercise market power and bid up to the scarcity price- although it still gains on the 10MW of availability in excess of the RO volume it sells into the energy market- i.e. on its last 10MW it does face the right marginal incentive;
- There is a surplus in this case (because generator's exposure to imbalance is not capped the RO), i.e. a negative hole in the hedge. In principle, any surpluses could be used to offset "holes in the hedge" on other occasions.

APPENDIX C. OPTIMAL APPROACH TO SELECTING A DEMAND SCENARIO – AN EXAMPLE

As discussed in Section 2, In determining the level of capacity that is required for the I-SEM it is necessary:

- For the TSOs to consult on a number of scenarios for the future level of demand; and
- That the TSO's then select one of those scenarios to form the basis of the capacity requirement.

The SEM Committee has decided that the relevant scenario should be selected using the "optimal" approach – which chooses the "least worst" scenario. This approach is illustrated below.

Scenario	Forecast Peak Demand (MW)	Capacity Requirement (MW)	VoLL (€k/MWh
1	6,700 MW	7,500 MW	€10k
2	6,850 MW	7,600 MW	€10k
3	7,000 MW	7,700 MW	€10k
4	7,250 MW	7,900 MW	€10k

1 Establish the Scenarios

	Regret cost of too much capacity				Increased MWh lost from too little capacity				Regret Cost (at VoLL) of too little capacity			
	"True" Scenario				"True" Scenario				"True" Scenario			
	1	2	3	4	1	2	3	4	1	2	3	4
CONE (€k/Mwy)	€50.00k	€50.00k	€50.00k	€50.00k								
Scenario Being Evaluated 1	€0k	€0k	€0k	€0k	0	67	670	3350	€0k	€670k	€6,700k	€33,500k
2	€5,000k	€0k	€0k	€0k	0	0	103	685	€0k	€0k	€1,028k	€6,850k
3	€10,000k	€5,000k	€0k	€0k	0	0	0	70	€0k	€0k	€0k	€700k
4	€20,000k	€15,000k	€10,000k	€0k	0	0	0	0	€0k	€0k	€0k	€0k

2 Evaluate components of Regret Cost

Combined Regret Costs	"True" Scenario				
	1	2	3	4	Max Regret
Scenario Being Evaluated 1	€0k	€670k	€6,700k	€33,500k	€33,500k
2	***€5,000k***	***€0k***	***€1,028k***	***€6,850k***	***€6,850k***
3	€10,000k	€5,000k	€0k	€700k	€10,000k
4	€20,000k	€15,000k	€10,000k	€0k	€20,000k

3
- Look at total Regret Cost
- Select Scenario with "least worst" regret cost

Figures are for illustrative purposes only

For this example, there are four scenarios for peak demand – ranging from 6,700 MW to 7,250 MW. These are evaluated as follows:

- **Step 1** evaluates each scenario to determine the total level of capacity required under that scenario
- **Step 2** evaluates the components of potential "regret" cost for each scenario. Key points about this step are:

- **Evaluate all combinations:** Each scenario is evaluated against all other scenarios. The scenario being evaluated is shown as rows, and in each case is evaluated as if the out-turn (or "true") demand was as shown in the relevant column.

- **Regret cost 1: Too much capacity:** If the outturn (true) demand is lower than that in the scenario being evaluated, using that scenario would lead to the purchase of more capacity than is required. In each case, the increase in capacity is priced at the expected cost of new-entrant capacity (in this case €50k/MW/y). This is shown in the left hand table on the middle row above.
- **Regret cost 2: Too little capacity:** If the outturn (true) demand is higher than that in the scenario being evaluated, using that scenario would lead to the purchase of less capacity than is required. This, in turn would increase the MWh expected level of unserved energy[81] – as shown in the second table on the middle row above. This unserved energy is priced at the Value of Lost Load (VoLL) – in this case, £10k/MWh.

  - **Step 3: Select the Least Worst:** The two components of regret cost are combined into a single table, and the worst regret cost for each is determined (see the "max regret" column of the bottom table in the figure). The scenario that has the lowest value in this column is selected as being the optimal scenario in a "least worst regret cost methodology.

[81] The TSO models used to determine LOLE are able to produce an estimate of unserved energy

APPENDIX D. WORKED EXAMPLE OF IMPLEMENTING OPTION 2 FOR DSUS

We have constructed worked examples to demonstrate, for the purposes of discussion, how Option 2 for DSUs might work and the implications.

In all worked example we assume:

- End consumer X has the ability to reduce its end consumption from 3MW (Baseline Quantity, BQ) to 2MW metered quantity (MQ), at an DSR price of €300/MWh
- As a result DSU Y contracts with X to back a 1MW RO with X's demand response and successfully bids this capacity into the CRM. The RO has a Strike Price of €500/MWh
- End consumer X has a contract with Supplier Z.

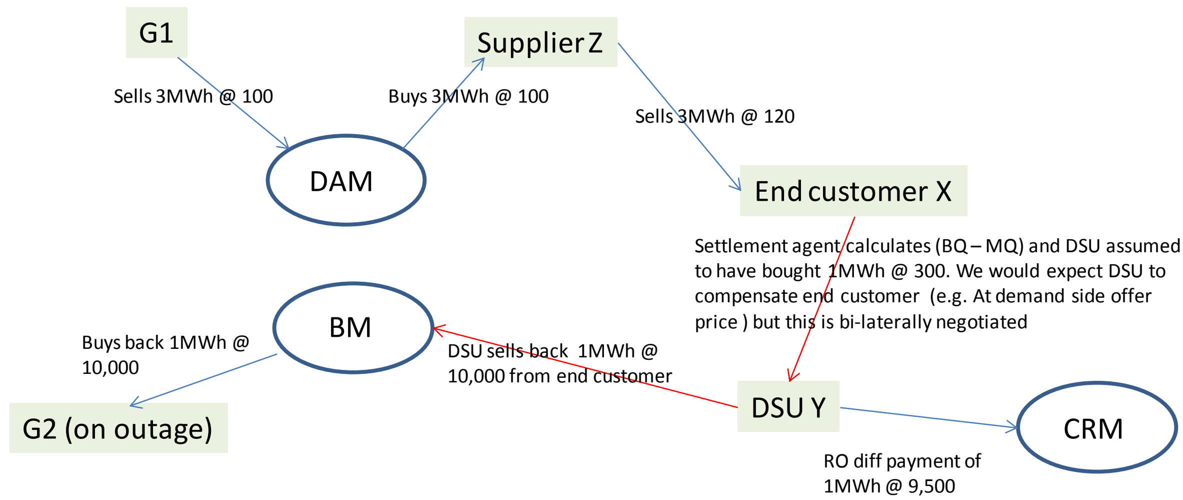
We show conceptually how Option 2 might work conceptually under different scenarios where the capacity, i.e. demand reduction is fully delivered and only partially delivered.

These scenarios demonstrate that if the concept can be implemented, it appears to deliver appropriate incentives and provides the DSU with the money to pay the RO difference payment.

Scenario 1: 1 MW Contracted DSR delivered, scarcity BM only

Example specific assumptions:
- Supply tariff fixed at €120/MWh
- DSU Y agrees contract offer price with X- similar to current demand side bid
- No scarcity at Day Ahead, DAM price is €100/MWh
- Scarcity in real time caused by generator outage of 1MWh

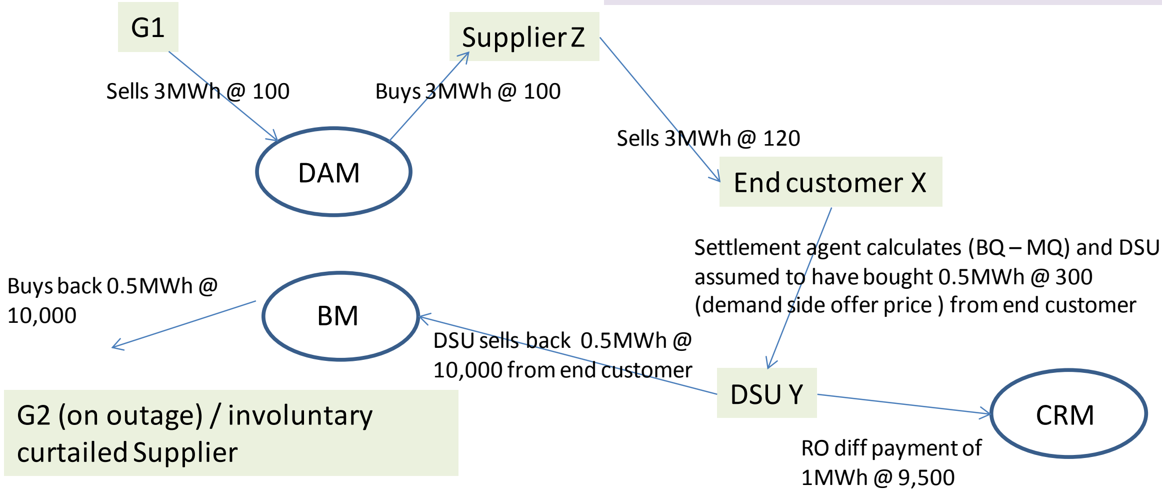
Key outcomes
- DSU has energy market net profit excluding option fee of 200 after paying RO difference payment
- Customer paid at offer for energy reduction
- Supplier unaffected by demand side response



Scenario 2: 0.5 MW of 1MW Contracted DSR delivered, scarcity BM only

Example specific assumptions:
- Supply tariff fixed at €120/MWh
- No scarcity at Day Ahead, DAM price is €100/MWh
- Scarcity in real time caused by generator outage of 1MWh

Key outcomes
- **DSU only paid for (BQ-MQ), but has to pay out difference payment on full 1MWh. So loses 9,500 – 5,000 -150 = 4,350.** DSU, appropriately penalised if customer does not deliver
- Customer not penalised for failing to honour demand side bid, unless additional contract terms inserted by DSU



APPENDIX E. HOLE IN THE HEDGE ANALYSIS

There are a number of factors that mean that, at times, there may be a deficit of difference payments in the CRM. That is, the difference payments received through the Reliability Options (ROs) are less than those required to fully hedge Suppliers against market prices that are above the RO Strike Price.

Causes of potential deficit

This deficit in difference payments can arise for a number of reasons:

- **Generator opt-out**: It may be that intermittent capacity chooses not to bid in the auction, and we will reduce the amount of RO purchase commensurate with the assumed capacity contribution of the non-bidding plant (to avoid paying for capacity we do not need). Given the likely de-rating of wind to around 10% of nameplate capacity, by 2024, we expect wind to contribute around *8% of de-rated capacity*.
- **DSU:** it is likely that, at least initially, DSUs will not be required to make RO difference payments as they will not receive energy payments for their customers' reduced load. DSUs account for about 200MW of capacity in the SEM, i.e. about *3% of peak demand*.
- **Stop Loss:** We plan to set stop-loss for generators, so that their uncovered difference payments (i.e. difference payments which are not offset against scarcity energy rents because they have not been able to generate to their RO volume during scarcity). We plan to set this stop-loss level as a multiple of annual fees in the range x1 annual fees to x2 annual fees. Where generators have hit their stop-loss limit, they no longer need to make difference payments when they fail to generate. We have done some estimates of the potential loss to suppliers and they are in the *range €0-35m p.a*. to Suppliers if there are 8 hours of lost load in a year, although this may not make full allowance for incidences of scarcity short of lost load.
- **Peak demand under-forecast**: if the scenario against which we set the capacity requirement outturns less than the actual peak demand, there will be a deficit. This is looking un-likely as we note that in GB:

- The "least worst" scenario selection tends to select a scenario with demand forecasts at the higher end of the range covered by the scenarios; and
- The total de-rated capacity requirement tends to be higher (between 101% and 106%) of the peak demand for the relevant scenario

We discuss some of these estimates further below.

Generator opt out

We are proposing to make it mandatory for dispatchable plant to participate in the CRM, but we are proposing to allow intermittent plant to opt out.

We have estimated the impact on the size of the hole in the hedge, if all intermittent wind plant opts not to compete in the CRM.

Given the likely de-rating of wind to around 10% of nameplate capacity, if all wind chooses not to participate, this will mean that the volume of Reliability Option sold would be around 8% less than peak demand (based on current installed wind), i.e. there is an approximately 8% "hole in the hedge". This hole would potentially grow as wind penetration increases, but the current Eirgrid projection do not have it growing much after 2021, as increasing wind installed capacity is partially offset by a reducing capacity factor.

Installed wind (MW)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
NI	1036	1094	1145	1205	1256	1297	1345	1389
Ireland	3219	3385	3520	3600	3727	3854	3982	4109
all-island	4255	4479	4665	4805	4983	5151	5327	5498
Capacity factor (interpolated)	11.8%	11.4%	11.2%	11.1%	11.0%	10.8%	10.5%	10.3%
Wind available to CRM auction (MW)	501.3	509.3	523.6	534.8	548.7	555.3	560.6	565.0
Peak demand (MW)	6700	6720	6760	6800	6810	6860	6920	7000
% coverage of RO hedge for suppliers	7.48%	7.58%	7.75%	7.86%	8.06%	8.09%	8.10%	8.07%

Effect of the stop-loss limit (penalty cap)

We will impose caps on the penalties imposed on capacity providers, in order to limit risk and improve investability. In practice, this means capping capacity provider difference payments, and if we cap the difference payments, there is a risk that if there are a number of hours of scarcity, there will not be enough money to hedge Suppliers.

The materiality of the penalty caps on the size of the hole in the hedge, depends inter alia on a number of factors, including:

- How the penalty cap is defined. If the cap applies only to *uncovered* difference payments when the capacity provider does not have an offsetting energy revenue (because it is on forced outage), then the cap will bind less often than if the cap applies to all difference payments, regardless of whether the capacity provider was generating and received the energy payment;

- Capacity security standard, and hence number of hours of scarcity
- The definition of administrative scarcity- if scarcity is defined narrowly as a lost load event, there will be fewer events of high price;
- The structure and level of the stop-loss limit (penalty cap):

- We may cap penalties at x1 annual capacity payments (as GB have done), or some higher multiple (e.g. x2 annual fees)
- We may cap penalties on a per month or per event basis[82];

- The auction clearing price (assuming that penalties are capped at a multiple of capacity payments)

We have done some high level analysis to assess the materiality of then hole in the hedge, based on the following assumptions:

- There are 8 hours of scarcity in a year;
- When scarcity occurs, there is an administrative scarcity price, with a variety scenarios of VoLL (SEM VoLL of €11,000/MWh), VoLL capped at £3000/MWh (GB BM until 2018/19), VoLL capped at £6000/MWh (GB BM from Winter 2019/19;
- Penalties caps are applied annually only[83], with penalties caps ranging from x1 annual fees to x2 annual fees);
- Auction clearing price which range from the lowest, the GB 2014 auction price (= €26.88/kW pa) to the highest 2015 SEM BNE (=€81.60/KW pa);
- The stop-loss limit applies to uncovered difference payments only, and the assumed unavailability rate is 10%.

The table below show the amount of Supplier difference payments that should be made, but cannot be recovered from generators due to this hole in the hedge.

The results vary very much depending on the assumptions from €0m to €37m hole in the hedge in the year across all suppliers. The €37m assumes a tight cap on penalties and high VoLL. The €37m estimate occurs where Suppliers have are exposed to scarcity pricing on all of their volume. This can only happen if:

- Scarcity is already apparent at Day Ahead stage; or
- Suppliers buy all their volume in intra-day markets or the BM after scarcity has become apparent.

Both of these scenarios are unlikely.

[82] To maintain incentives to provide capacity for the remainder of the year

[83] For simplicity- otherwise, we would need to make assumptions and do sensitivities on whether scarcity hours were grouped in particular events or months

Hole in hedge in €m

Scenario: ASP = SEM VoLL

	Penalty cap		
Auction clearing price	**x1 annual fees**	**x1.5 annual fees**	**x2 annual fees**
2015 SEM BNE	2	-	-
2016 SEM BNE	8	-	-
1/2 2016 SEM BNE	31	20	8
GB CONE	16	-	-
GB clearing	37	29	20

Scenario: ASP = GB VoLL (from winter 2015/16 = £3000)

	Penalty cap		
Auction clearing price	**x1 annual fees**	**x1.5 annual fees**	**x2 annual fees**
2015 SEM BNE	-	-	-
2016 SEM BNE	-	-	-
1/2 2016 SEM BNE	-	-	-
GB CONE	-	-	-
GB clearing	4	-	-

Scenario: ASP = GB VoLL (from winter 2018/19 = £6000)

	Penalty cap		
Auction clearing price	**x1 annual fees**	**x1.5 annual fees**	**x2 annual fees**
2015 SEM BNE	-	-	-
2016 SEM BNE	-	-	-
1/2 2016 SEM BNE	18	7	-
GB CONE	3	-	-
GB clearing	24	16	7

Peak demand under forecast

As discussed in Section 2, the amount of capacity procured will be set in relation to the capacity standard, and depends upon:

- The capacity standard chosen; and
- The demand scenarios, which are in part a function of the capacity methodology.

Since the capacity methodology reflects an expectation of forced outages, it is likely that the amount of capacity procured will exceed the peak demand.

In GB, National Grid estimated the excess of capacity required to meet capacity standard as between 1% and 6% in excess of Average Cold Spell (ACS) demand, with the surplus at around 4% in most scenarios (see table below).

Table E.1: National Grid forecast of capacity procured versus peak demand

Scenario	**Capacity to Procure (GW)**	**Outside CM (GW)**	**Total derated capacity (GW)**	**ACS Peak (GW)**	**Margin (% of ACS peak)**
Slow Progression low demand SP_LOW_DEMAND	46.1	14.8	60.8	58.3	4.3%
Consumer Power low demand CP_LOW_DEMAND	46.1	15.2	61.4	58.7	4.6%
DECC Scenario DECC	46.2	15.1	61.3	58.9	4.1%
Slow Progression warm winter SP_WARM	46.4	14.7	61.1	60.3	1.3%
Consumer Power warm winter CP_WARM	46.5	15.1	61.6	60.7	1.5%
Gone Green GG	47.0	15.0	61.9	59.3	4.4%
Slow Progression high availability SP_HIGH_AVAIL	47.7	14.8	62.5	60.3	3.6%
Consumer Power high availability CP_HIGH_AVAIL	47.9	15.2	63.1	60.7	4.0%
Slow Progression SP	48.0	14.8	62.8	60.3	4.1%
Consumer Power CP	48.1	15.3	63.4	60.7	4.4%
Slow Progression Low availability SP_LOW_AVAIL	48.2	14.8	63.1	60.3	4.6%
Consumer Power Low availability CP_LOW_AVAIL	48.3	15.3	63.6	60.7	4.8%
Slow Progression high demand SP_HIGH_DEMAND	48.5	14.8	63.4	60.8	4.3%
No Progression NP	48.6	14.3	62.9	60.5	4.0%
Consumer Power high demand CP_HIGH_DEMAND	48.7	15.3	64.0	61.2	4.6%
Slow Progression low wind SP_LOW_WIND	48.8	14.0	62.8	60.3	4.1%
Consumer Power low wind CP_LOW_WIND	48.9	14.5	63.4	60.7	4.4%
Slow Progression cold winter SP_COLD	49.0	14.9	63.9	60.3	6.0%
Consumer Power cold winter CP_COLD	49.1	15.4	64.4	60.7	6.1%

Source: National Grid EMR, electricity Capacity Report, June 2015

We note that the capacity standard in the I-SEM will be based upon a 3 hour LOLE standard as opposed to the 8 hour standard in GB, and all other things being equal this will lead to a lower excess of capacity requirement over peak demand. However, as the I-SEM is a smaller system, and capacity is likely to be installed in larger increments relative to system size, this effect may be limited.

In the event that peak demand is correctly forecast, if scarcity occurs at peak demand, all Suppliers will be hedged via the RO.

However, if the chosen demand scenario under-estimates the peak demand, and a scarcity event happens when actual demand is above the peak demand assumed in setting the capacity requirement, there will be a hole in the hedge. This can happen if capacity providers are able to deliver more than their de-rated capacity during the event, but not enough to meet unexpectedly high demand.

It would be unfair to increase capacity providers' difference payments to cover the shortfall (i.e. have load following upwards, as well as downwards) and undermine investability.

The risk is partially a function of RA policy parameters. If we choose to procure capacity to a worst case scenario, the risk is lower than if we choose to procure to an average scenario. We note that the chosen approach, the "least worst" scenario selection tends to select a scenario with demand forecasts at the higher end of the range covered by the scenarios. We consider that the under-estimate is unlikely to be more than about 2-3% of peak demand.

Causes of potential surplus

Any difference payment deficit is also (at least partially) offset by a potential that, at times, there will be a surplus of difference payments in the CRM. That is, the difference payments received through the Reliability Options are greater than those required to fully hedge Suppliers against market prices that are above the RO Strike Price. This surplus is a feature of the fact that difference payments are only paid to Suppliers that buy in the I-SEM markets – with no difference payments paid to

Generators that buy back generation to cover their outage. For example, this surplus could (and is likely) to occur following a generator trip, as follows:

- At the Day Ahead stage, Suppliers purchase sufficient power to cover their forecast of the demand of their customers. The Day Ahead Price may be above the RO Strike Price; however (for this example) there is no hole in the hedge at the Day Ahead stage
- Between Day Ahead and delivery, two things happen that give rise to a need to trade:

- Suppliers become aware of errors in their demand forecasts – so trade to match their contract position with their expected physical position. This leads to either Supplier to Supplier trades, or Supplier to Generator Trades.; and
- A generator fails – so has to buy back the output it had otherwise sold. This will lead to generator to generator trades.

Experience from other markets suggest that the generation failure will be the dominant driver of prices in the short term, and will drive those prices higher than those seen in earlier (e.g. Day Ahead) markets. This increase in price will increase the level of difference payments made; however, the difference payments received will not be circulated to generators that have bought in the market (i.e. the generator that has failed). This will lead to the surplus.

Summary estimates

The total net effects are summarised in Table E.2 below.

Table E.2: Best estimate of potential surplus or deficit

Driver	Estimate of impact	Key dependencies
Intermittent generator non-participation	Deficit: Up to 8% of demand uncovered	Deficit decrease with level of wind and other intermittent
DSUs participation	Deficit: Up to 3% of demand uncovered	Deficit increases with level of DSU participation
Stop-loss provisions on generators	Deficit: 0 - €37m p.a. to Suppliers in aggregate	€35m is based on an assumption of: 8 hours of scarcity with a price at full SEM VoLL; participating generators have a 10% outage

		rate; a low annual fee based on GB2014 auction, so the stop-loss applies quickly; extremely pessimistic assumptions that Suppliers only procure energy after scarcity has occurred;
Peak demand under forecast	Deficit: 2-3% of demand uncovered?	capacity requirement approach
Procurement in excess of demand to meet	Surplus: 1-6% of demand?	Capacity standard, de-rating approach
Generator outage not high demand is driver of scarcity	Surplus: unknown	Whether scarcity is caused by high generator outages and high demand relative to expectation

APPENDIX F. THE MRP, FORWARD CONTRACTING AND RISK MANAGEMENT

In the SEM Generators and Suppliers can hedge their market risk through the use of two-way CfDs (subject to liquidity constraints).

There have been a number of consultation respondents who have argued that introduction of the RO based CRM introduces significant basis risk and complexity into forward hedging, particularly if the Balancing Mechanism price is a component of the MRP.

This note examines the extent to which:

- There is additional risk for Generators and Suppliers under our strawman option (Option 4b) relative to the current market;
- How much of that risk is a function of the I-SEM move to a two-settlement energy market and away from single settlement against an ex post Pool price;
- How much of the risk is a function of introducing an RO based CRM (as opposed, for instance to overlaying a GB style CRM); and
- How much of the risk is a function of introducing a BM element into the MRP, as opposed to the using a purely DAM MRP, which is the preferred option of many respondents.

The key conclusions are:

- The move to a two-settlement energy market gives Suppliers the opportunity to trade out shape risk and volume reforecasts up to Day Ahead stage-i.e. at Day Ahead rather than the more volatile real time prices. They do not have this opportunity in the SEM, where the Pool price is a real time ex-post price, and there is no liquid DAM.
- The split price MRP leads to similar outcomes for a hedged generator and supplier as in the analogous SEM scenario in the event of a generator forced outage that occurs close to real time- apart from the potential introduction of VoLL based pricing.
- The split price MRP gives a supplier price protection on volume variances (which by will not be hedged, since they were unforecasted) that they do not have in the SEM, or would not have with a DAM MRP, although:
- A BCoP similar to that operating in the SEM gives most of the protection against prices that reflect scarcity[84];
- Arguably they should be exposed to the full marginal price on these volume variances.
- By the same token it caps a generators ability to exert market power.

[84] Depends on BCoP

Forward contracting and risk in the SEM

In the SEM, any generator wishing to hedge its Pool price risk on its expected output can hedge it by selling a two-way CfD in forward markets- any up to two years ahead of delivery is quite typical. Similarly, any supplier can hedge its Pool price risk by buying a CfD.

A theoretical perfectly reliable generator will sell forward based on its expected output. If a generator is a baseload generator, it can lock out almost all of its Pool price risk via a baseload CfD, as it gets paid the ex-post Pool price for its physical power and the CfD ensures that the net effect is that the generator gets CfD Strike Price.

Typical generators are not perfectly reliable, so are exposed to some residual risks:

- **Shape ris**k. Liquidity in forward CfD is limited to some standard baseload, mid-merit and peak contracts and generators will be exposed to residual “shape risk”, i.e. price risk on the difference in volume between its detailed forecast hourly profile and the standard instrument that are traded. This detailed shaped volume is also exposed to the real time ex-post Pool price.
- **Volume risk**. In practice, a generator will not be able to forecast its output with certainty in forward timescales, and its actual output will be different from that forecast in forward timescales. This includes differences between forecast and actual output due to changes in merit order, forced outages, and unforecast changes in demand. This difference between forecast and actual is exposed to the real time price, the ex-post Pool price.

Similarly, a Supplier looking to hedge its customer tariff offerings is exposed to the real time Pool price on:

- Shape risk- the difference between the detailed hourly profile of its customers and the standard traded instruments; and
- Volume risk- i.e. difference between forecast demand in forward timescales and real time demand.

If scarcity occurs in real time, they will be exposed to scarcity prices on all their shape mismatch and volume differences relative to the amount they hedged in forward markets.

In the SEM, SRMC based bidding limits the volatility of the real time price, although the uplift formula increases the volatility in certain hours in a way that is hard to predict.

How does the change to a two-settlement energy market change forward contracting and risk?

With the move to the I-SEM, generators looking to hedge in forward timescales can still sign forward two way CfDs for volumes equivalent to their forecast output. The working assumption is that these CfDs will be struck against the I-SEM DAM price. As now, they will be exposed to shape risk and volume risk. However, unlike in the SEM, the presence of a firm Day Ahead price in the liquid DAM means that they can mitigate their risk at Day Ahead stage:

- Shape- they can hedge the shape mismatches they were unable to hedge via hourly granularity DAM bidding;
- Volume risk- at Day Ahead stage they will have a much better estimate of their generation output than in forward timescales, and they will be able to fix the price of the volume forecast deltas at Day Ahead prices.

If we assume that scarcity pricing is never evident at Day Ahead stage only becoming evident in real time, they will only be exposed to scarcity prices on any differences between Day Ahead forecast volumes and real times volumes- typically due to forced outages and unpredictable wind output variations.

The same holds true for Suppliers, they hedge most of their exposure to scarcity based pricing at Day Ahead stage, and are only exposed to the real time prices on differences between Day Ahead forecasts of customer demand and actual customer demand.

Therefore for both generators and suppliers, the move to two-settlement with a liquid DAM (but in the absence of an RO) allows them to reduce their exposure to real time price in a way which they cannot do in the SEM.

Whilst in principle, in the SEM if the supplier had had a CfD which covered the detailed shape and the volumes forecast variances which occur in real time, then they would have had more protection, since the SEM CfD settles against the ex-post price not a DAM price. But the reality is that they would not have had CfDs to cover these volumes under the SEM, so the move to two-settlement improves their risk management ability because it enables them lock out their detailed shape and reforecast volumes at Day Ahead prices, which they cannot do in the SEM (because there is no liquidity in shaped CfDs or Day Ahead CfDs).

How would introduction of an RO with a DAM MRP change contracting and risk exposure

If an RO was introduced with a DAM reference price, then the two-way CfDs would need to be changed so that the two-way CfDs would disapply above the reference price.

A supplier wishing to hedge in forward timescale would hedge as before, but with the “new” CfDs. From the supplier perspective, the combined effect of the “new” CfD and the RO fully hedges its price risk on the volume that it is able to hedge in forward markets. As above, it will trade out its detailed shape exposure and its re-forecasted volume at the Day Ahead stage. Therefore, the supplier is better off than under the current SEM, as in the above example.

The RO acts to further cap its exposure to high Day Ahead prices at the RO Strike Price. However, if the RO Strike Price set high, and scarcity pricing is never manifest at Day Ahead stage the RO will provide little if any additional hedging benefit.

The supplier will still be exposed to scarcity based pricing of differences between its Day Ahead forecast volume and its actual real time consumption.

From the generator perspective, there is little risk. If the generator sells more in the DAM than its forecast output in forward timescales (i.e. its CfD volume), then the net price it receives is capped at the RO Strike Price, if this volume is still less than its RO volume. However, this should not be a material risk to the generator. Provided the RO Strike Price is set above its marginal cost[85], it only caps the upside.

How would a BM MRP change contracting and risk exposure

Consider now the case where there is a BM MRP instead of a Day Ahead MRP. Let us assume that the "new" CfDs are still referenced to the DAM price, and disapply above the point where the DAM price exceeds the RO Strike Price.

A supplier will be able to hedge in forward timescales, and then lock out its residual shape risk and reforecasted volumes in the DAM at Day Ahead prices, which are unlikely to fully reflect scarcity[86]. However, the RO will now cap the suppliers' exposure to high BM prices on volumes changes that occur between the Day Ahead stage and real time.

This affords suppliers with protection over and above what they receive under the SEM design, by capping their exposure to real time prices on the shape and volume risk- which they cannot hedge in the SEM.

From the generator perspective, the key risk is that they have to pay out differences payments on the whole RO volume at BM prices which reflect scarcity, even though they have sold all their volume in the DAM.

The problem is illustrated in the following example:

- A generator has 100MW nameplate capacity, de-rated to 90% so has an RO volume of 90MW. The RO strike is €500/MWh;
- A year ahead it sells forward 90MW at its two way CfD strike of €150/MWh, the expected outturn DAM and BM price. The 90MW reflects a probability weighted estimate of its output in any given settlement period
- At DAM stage it has a low probability that it will breakdown in the next day, so sells forward its full 100MW nameplate, still at a price of €150/MWh
- In real time another generator has an outage, and the price rises to scarcity levels, €900/MWh.

Now the generator's net revenue =

- Physical power in DAM = 100 x 150 = 15,000

[85] Although start up costs may be an issue

[86] This is based on the assumption that most scarcity events are driven by forced outages, that are difficult to forecast at the day-ahead stage

- Two-way CfD payment = 90 x (150 – 150) = 0
- RO payment = -90 x Max(900 – 500,0) = -36,000
- Total = -21,000

So the key issues are that:

- The generator which has delivered its full nameplate capacity and behaved exactly as we would like to behave in the contracting market, has lost money
- The supplier has received a BM price “over-hedge” on volumes it did not need hedged, volumes in had procured in the DAM.

How would a split price (Option 4b) MRP change contracting and risk exposure

In the split market example, let us assume that generators and suppliers hedge in forward timescales as before. Shape and volume known at Day Ahead stage is locked out as before.

However, suppliers are also protected on their exposure to high BM prices on volume changes that occur between the Day Ahead stage and real time in a way which they are not either in the SEM, or if there was a DAM MRP, or in a GB style CRM. There is a question however, as to whether it is economically efficient for the supplier to receive this protection against price risk on volumes it did not purchase at Day Ahead stage, or whether it should face the marginal energy price on these volumes.

From the generator perspective if they hedge forward with two way CfDs and deliver the physical volume in the DM market they are protected- they will be guaranteed net revenue equal to the two-way CfD strike.

Consider the above example, but with a split price MRP instead of a DAM MRP. In that example the generator’s net revenue is:

- Physical power in DAM = 100 x 150 = 15,000
- Two-way CfD payment = 90 x (150 – 150) = 0
- RO payment = -90 x Max (150 – 500,0) = 0
- Total = 15,000

i.e. the generator has received a fair net revenue for the energy sold in the DAM.

The key risk is if that the generator is the generator that has the outage and causes the scarcity. Assuming this happens close to real time, then the generator’s net revenue is:

- Physical power in DAM = 100 x 150 = 15,000
- Two-way CfD payment = 90 x (150 – 150) = 0
- BM imbalance = -100 MW x 900 = -90,000
- RO payment = -90 x Max (150 – 500,0) = 0

- Total = -75,000

The key is to ensure that the generator s not double penalised at the imbalance price. Because the generator has sold power forward in the DAM, this RO volume needs to be settled against the DAM price, even though the power does not end up being physically delivered. This works because:

- The penalty for the generator is having to buy back at the high BM price
- The generator which replaces the outage is paid appropriately through the BM
- No supplier needs a hedge, it is simply one generator buying from another generator to cover its outage

If we were to cash out the RO against the BM price, the generator would be double penalised.

Moreover, consider how the generator is affected relative to the current SEM- let us assume that in the current SEM the forced outage occurs close to real time. In an analogous SEM event, the ex ante Pool price would have been €150/MWh and the ex-post Pool price €900/MWh. Generator payments work as follows:

- SEM energy payment= 0 x 900 = 0
- Two way CfD payment = 90 x (150 – 900) = -67,500
- Total = -67,500

In this example, the generator is slightly worse off under our new design, because it ends up having to buy back the full 100MW volume it expected at Day Ahead stage to produce, rather than having just to make a difference payment on the average de-rated 90MW volume.

Consider now the example, where the I-SEM forced outage is a long outage, so for the next day the generator knows that it will not be able to produce, and does not sell into the DAM. Let us assume that because of prolonged outage, the scarcity is now expected at Day Ahead stage, so the DAM and BM prices are €900/MWh. The generator's net revenue is as follows:

- Physical power in DAM = 0 x 900 = 0
- Two-way CfD payment = 90 x (500 – 150) = -31,500 since caps out at RO strike
- BM imbalance = 0
- RO payment = -90 x Max (900 – 500,0) = -36,000
- Total = -67,500

i.e. an identical result to the SEM

The key difference is where the scarcity was caused by a sudden within day spike in demand, rather than a generation outage. In this case, the supplier is protected up to peak demand by the RO, and generators' income is capped at the RO Strike Price.

The key conclusions are:

- The move to a two-settlement I-SEM energy market gives suppliers the opportunity to trade out the shape risk and volume variations in the DAM, but leaves them exposed to price risk on volume variances between Day Ahead stage and real time.

- In theory, a DAM based RO would give the Suppliers additional protection, as it would cap the price on volumes not hedged in forward markets, but hedged at Day Ahead stage. However, this additional hedge is unlikely to be of much value, since the cap will only take effect if pricing reflects scarcity, which is less likely in Day Ahead timeframes. It leaves them price exposed on supplier volume variances that occur between Day Ahead stage;
- The split MRP RO will give Supplier's protection against scarcity prices on volume variances post Day Ahead, when it is more valuable to them. However, arguably they should be exposed to the marginal energy price on within day volume variances.
- Generators still have an incentive to hedge in forward markets under the split price MRP:

- Provided they sell into the DAM and deliver the volume they will be hedged at the CfD Strike Price.
- If they have a forced outage they will be in a similar situation to the same SEM generator, particularly where that outage is already known at Day Ahead stage.

APPENDIX G. EIRGRID MRP OPTION

Initial BM reference price model:

	$\boldsymbol{Generator\ payment}\ ENPuh$	$\boldsymbol{Supplier\ charge}\ ENCvh$
DAM/IDM Trades	$+EAPh \times EAQuh$	$-EAPh \times EAQvh$
Energy Imbalances	$+IMBPh \times (MQuh - EAQuh)$	$-IMBPh \times (MQvh - EAQvh)$
RO Difference Payments	$-Max(IMBPh - STRPy, 0) \times ROQuh$	$+Max(IMBPh - STRPy, 0) \times ROQvh$

Where

- *EAPh* = Ex-ante market price(s) in trading period h
- *EAQu(v)h* = Ex-ante market quantity for generator u (supplier v) in DAM & IDM in trading period h
- *IMBPh* = (Real-time) imbalance price in trading period h
- *STRPy* = RO Strike Price in year y
- *MQu(v)h* = Metered quantity for generator u (supplier v) in trading period h
- *ROQu(v)h* = RO quantity (scaled) for generator u (supplier v) in trading period h

Issue: trade in DAM is exposed to basis risk as RO is referenced against BM. Participants will avoid DAM as a result. (E.g. if MQ=EAQ=ROQ and EAP < STRP << IMBP, energy imbalances are zero and RO difference payments will exceed value of DAM/IDM trades. The reason is that by trading in the DAM/IDM, the unit is foregoing payment of IMBP; however, the unit has to pay back the part of the IMBP that exceeds the STRP. Moreover, if the unit does not fully deliver its DAM/IDM trade (MQ<EAQ and MQ<ROQ), it faces a double exposure to the IMBP.

Proposal: remove the basis risk in settlement by capping energy imbalance settlement at the STRP and paying any component of IMBP above the STRP based on MQ (which will then be paid back based on ROQ). This essentially creates two forms of imbalance: (a) Energy Imbalances i.e. difference between MQ and EAQ at the component of IMBP below the STRP and (b) Reliability Imbalances for differences between MQ and ROQ at the component of IMBP above the STRP. It is possibly simpler in the revised algebraic form (new parts in red):

	$\boldsymbol{Generator\ payment}\ ENPuh$	$\boldsymbol{Supplier\ charge}\ ENCvh$
DAM/IDM Trades	$+EAPh \times EAQuh$	$-EAPh \times EAQvh$
Energy Imbalances	$+Min(IMBPh, STRPy) \times (MQuh - EAQuh)$	$-Min(IMBPh, STRPy) \times (MQvh - EAQvh)$

Reliability Imbalances	$+Max(IMBPh - STRPy, 0) \times (MQuh - ROQuh)$	$-Max(IMBPh - STRPy, 0) \times (MQvh - ROQvh)$

Note as ROQvh is load following, MQvh=ROQvh. Therefore, Reliability Imbalances for suppliers are always zero by definition. Also, for units who deliver on their Reliability Option i.e. MQuh=ROQuh, Reliability Imbalances are also zero. For these generators and suppliers, the algebra becomes:

	$\textbf{Delivery by RO generator}\ (ENPu$	$\textbf{Supplier charge}\ ENCvh$
DAM/IDM Trades	$+EAPh \times EAQuh$	$-EAPh \times EAQvh$
Energy Imbalances	$+Min(IMBPh, STRPy) \times (MQuh - EAQuh)$	$-Min(IMBPh, STRPy) \times (MQvh - EAQvh)$
Reliability Imbalances	0	0

Units that do not deliver against their RO quantity pay units exceeding their ROQ that deliver in their place. For units with ROQ=0, energy and reliability imbalances collapse into the original imbalance settlement. Units that do not deliver their EAQ or ROQ have a single exposure to the imbalance price.

	$\textbf{Non delivery by RO Generator}\ (E$	$\textbf{Delivery by Non RO Generator}\ (E$
DAM/IDM Trades	$+EAPh \times EAQuh$	$+EAPh \times EAQuh$
Energy Imbalances	$+Min(IMBPh, STRPy) \times (0 - EAQuh)$	$IMBPh \times (MQuh - EAQuh)$
Reliability Imbalances	$+Max(IMBPh - STRPy, 0) \times (0 - ROQuh)$	