# Response by Energia to SEM Committee Consultation SEM-15-044

***I-SEM Consultation on the Capacity Remuneration Mechanism Detailed Design***

**17 August 2015**

# Contents

# Executive Summary

Energia welcomes this opportunity to respond to the SEM Committee consultation paper SEM-15-044 on the CRM for the I-SEM Detailed Design.

Reliability Options (ROs) are effectively a centrally administered energy contract with a 'bolt on' capacity mechanism (e.g. a capacity requirement, eligibility criteria, physical backing, performance incentives, etc.). The design of the energy contract component (the reliability option) used in an RO scheme therefore has the potential to impose significant commercial risks on participants (e.g. basis risk) that could significantly impact wider energy market dynamics. It therefore requires very careful consideration. A further cause for concern is that the energy contract component occupies the same market space as normal forward energy contracts (e.g. 2 way CfDs) that under an RO scheme remain essential for generators and suppliers to manage commercial risks. This latter issue is particularly problematic in the context of the I-SEM, given the liquidity issues already prevalent in the SEM forward contract market.

Careful consideration therefore needs to be given to the interactions between ROs and the I-SEM forward contract market to ensure the design of reliability options does not interfere with, or destabilise, the normal operation of the I-SEM forward contract market. Such an outcome would undermine the risk management activities of participants, is likely to increase commercial risk premiums on trading activities, and would therefore result in a direct increase in costs to consumers.

Viridian commissioned NERA to provide a report, submitted along with this response, which considers a number of important design aspects of the proposed RO scheme for I-SEM, including the setting of strike prices and the Market Reference Price; capacity requirements and obligations; and penalties and enforcement. We trust it will be of interest to the regulatory authorities (RAs) and their advisors.

Some of the conclusions drawn in the NERA report[1] regarding the implementation of ROs in the I-SEM context are as follows:

**On the level of strike price –** *"All other things being equal, the lower the strike price, the larger the volume of capacity holders' remuneration flowing through the capacity market, and the larger the unnecessary risks and costs that will ultimately be borne by consumers. ISO-NE is proposing to eliminate the Peak Energy Rent adjustment from its CRM, due to its poor performance as a hedge for Loads and the fact that hedging can be provided adequately by other means. This change would eliminate the problem for generators identified here". (p.2)*

[1] NERA, 14 August 2015, 'The Capacity Remuneration Mechanism in the I-SEM – Detailed Design'.

**On the choice of Market Reference Price –** *"Taking the MRP from the Balancing Market would align all prices and risks, but would cause trade to focus on the BM and to shift away from the Day-Ahead Market. That might harm the liquidity of cross-border market coupling. Forcing market participants to trade in the DAM would create basis risk unless either the MRP was taken from the DAM or the MRP was taken from the BM and market participants could use virtual bids to transfer electricity from the DAM to the BM.*[2] *The Intra-Day Market will not be liquid enough to provide a relevant MRP. Mixed schemes for defining the MRP bring additional complexity into the settlement of ROs and CFDs. As such, they increase the difficulty of hedging whilst offering little if any reduction in the exposure to basis risk".* (p.2)

Given the potential risks an RO type scheme poses for the I-SEM forward contract market, and the conclusions of the NERA report quoted above, Energia has deep reservations regarding the implementation of ROs as the capacity mechanism for I-SEM. Whilst such instruments may have had some conceptual appeal when considered at the high level design phase, their implementation is fraught with difficulties; notably associated with their interaction with energy market dynamics and the forward contracting market. These difficulties are openly revealed in the current consultation paper and have no clear resolution, as the NERA report helps to illustrate. This presents risk management problems for market participants which can only translate into less choice and higher prices for end customers. The added complexities associated with the implementation of ROs also gives rise to project risks, especially given the aggressive timetable for I-SEM go-live. We understand that delivery of ROs in Italy has been significantly delayed because of complexities in introducing the scheme.

We also note that reforms are ongoing in other markets that have ROs with fundamental changes being implemented to the ISO-NE scheme which is heavily referenced by the RAs to inform the I-SEM design. It is highly pertinent that said reforms in ISO-NE, as informed by the NERA report, include a proposal to eliminate the Peak Energy Rent (PER) adjustment (i.e. the payment back to the system in circumstances where the market prices exceed the defined strike price) in conjunction with the pay-for-performance reforms.

It is further instructive to note that GB decided against ROs, having considered them, for the following reasons[3] which resonate with the concerns we substantiate in this response:

*"…there are a number of drawbacks [with ROs]:*

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[2] NERA go on to identify issues with the implementation of "virtual bidding" in the I-SEM context, including in relation to market power and manipulation of a market reference price.

[3] See 'Electricity Market Reform: policy overview – Annex C', paragraph 71, published by DECC in November 2012.

- *While there may be some scope to provide for consumers who suffer blackouts to receive some compensation, this model offers less assurance that blackouts will be prevented – that is, there would be no checks to ensure that capacity providers have sufficient capacity and will be available when required.*
- *The potential level of liabilities that providers are exposed to are in effect "uncapped" – which could increase the risk to which holders of capacity agreements are subject, increasing participants' costs and therefore the overall costs of the Capacity Market.*
- *This model may have a greater impact on liquidity in the forward electricity market as capacity providers may seek to hedge the risk they are exposed to in the Capacity Market by selling electricity in the reference market".*

Given the strictures of State Aid approval that will apply to the scheme in I-SEM a prudent approach should be taken as further reforms at a later date (for example to eliminate the CfD aspect of the scheme as ISO-NE is doing) may be difficult and lengthy to implement.

In light of the above we would therefore urge the SEM Committee to re-evaluate the merits of moving forward with ROs for I-SEM at this stage, before expending further scarce resources and time on their design, and would suggest that a GB type scheme would be worthy of consideration.

NERA also drew the following conclusions on determining capacity requirements and penalties and enforcement:

**On capacity requirements and obligations –** *"…to maximise transparency and efficiency, the RAs should specify formulae that define how the capacity requirement is calculated and how de-rating factors for new and existing plants will be measured; as far as possible, these formulae should use observable public data (i.e. historical data, not someone's forecasts). For the sake of adaptability and stability, such rules should as far as possible be unrelated to specific technologies (which may change in future), but should use instead plant-specific data."* (p. 3)

**On penalties and enforcement –** *"Rewards and penalties based on performance during times of system stress are the fundamental drivers than ensure the CRM solves the "missing money" problem. RO settlement gives capacity providers no additional incentive other than the market price, so they may lack the incentive to provide sufficient capacity. In such circumstances, CRMs must be bolstered by additional penalties and rewards for providing more or less physical capacity during periods of system stress.*

*These rewards and penalties need to be targeted to encourage efficient decisions without creating unnecessary risks. The availability of any capacity may be affected by both internal and external factors – i.e. factors that are* *within the control of the plant operators (like maintenance) and factors that are outside their control (like the level of wind). When availability depends on external factors, then imposing penalties on capacity providers offers no additional incentive, whilst the additional risk of penalties outside their control discourages capacity providers from building capacity and participating in the scheme."* (p. 3)

NERA also suggest that the design of the CRM would benefit from further industry input in the following areas:

- on the implications of particular strike prices and MRPs for risk and liquidity, organised as a **workstream on pricing**;
- on the technical and plant-level data to be used in CRM formulae, organised as a **workstream on capacity definitions**; and
- on the economic and financial parameters used to define and limit rewards and penalties for providing capacity, organised as a **workstream on enforcement**. (We would emphasise that this workstream also needs to also carefully consider the implications of performance incentives within the context of wider market power concerns in the I-SEM.)

Energia fully supports these recommendations and furthermore suggests that there is a need for further input from industry on credit cover and collateral requirements, noting that ROs increase the credit burden relative to other schemes. We suggest a workstream is established to consider these issues across all I-SEM and DS3 markets and timeframes to ensure that the overall credit requirements placed on participants is optimised, providing sufficient collateralisation whilst minimising credit cover requirements.

Noting the complexity associated with taking investment decisions Energia would also recommend that there is further debate with stakeholders on pre-qualification requirements, Implementation Agreements, and performance incentives during the pre-commissioning phase. This could be accommodated via a working group proposed for this area.

We would welcome further dialogue with the RAs on the issues raised in this response, particularly on how the potential liabilities providers are exposed to under reliability options (ROs) will be managed to reduce participants' costs and therefore the overall costs of the capacity market; how the impact of ROs on liquidity in the forward market will be minimised; and how the CRM design could be simplified to substantially reduce the implementation risks for the project.

# 1. Introduction

Energia welcomes this opportunity to respond to the SEM Committee consultation paper SEM-15-044 on the CRM for the I-SEM Detailed Design.

Viridian commissioned NERA to provide a report, submitted along with this response, which considers a number of important aspects of the proposed design. We trust this will be of interest to the RAs and their advisors. It covers the following topics:

- Setting strike prices and the Market Reference Price;
- Capacity requirements and obligations; and
- Penalties and enforcement.

The remainder of this response is structured as follows. Section 2 provides general comments and proposed next steps. Section 3 responds to the specific questions posed in the consultation paper. Annex 1 provides a list of the principal reports referenced within this response.

# 2. General Comments

## *2.1 Are Reliability Options the right choice for I-SEM?*

The timetable for the design and implementation of I-SEM (and DS3) is extremely challenging but Energia is fully committed to its delivery. There is some acknowledgement in the current consultation paper that more complicated capacity mechanism design features (such as multiple zone auctions or locational pricing) would be challenging to achieve within the current I-SEM programme. However there are many complicated aspects to implementing the RO scheme revealed throughout the paper; predominantly due to the potential commercial risks it imposes on participating generators and its impact on potential energy market dynamics, including market trading incentives (influenced for example by the level of strike price and choice of reference market). Furthermore, we know from experience in other markets that the option component of an RO scheme in itself tends not to be sufficient to deliver provision of energy at times of system stress, and requires augmentation by other additional performance incentive measures. This is because, in practice, the strike price for the RO needs to be set high to avoid significant complications around the implementation of ROs[4]. This in turn negates the efficacy of the reliability option 'as a hedge'. A further complication of RO implementation relates to the potential 'hole in the hedge' provided to end consumers[5].

[4] These complications are discussed further in section 3 of this response and are evidenced by the conclusions drawn in the NERA report accompanying this response.

[5] This is covered in section 3.7 of the consultation paper and was discussed extensively at the industry workshop on 31 July 2015 in Dundalk.

Another major drawback of the RO type scheme in the context of I-SEM is that, regardless of the deemed eligibility status of wind generation, the complexity of the mechanism and the commercial risks it imposes mean that in practice wind is unlikely to accept / secure a contract unless the strike price is set extremely high and wind generation is exempted from RO pay outs, or at least its downside exposure is capped at a low level. The latter options effectively add to the 'hole in the hedge' issue given the projected levels of wind penetration in I-SEM. To effectively exclude wind from the mechanism however (by not providing relief from the commercial risks) would seem contrary to wider environmental policy objectives in relation to renewables targets, given the negative effect it would have on existing projects and securing financing for future wind generation projects.

Thus whilst ROs may have had some appeal conceptually when considered by the RAs at the high level design phase they quickly lose their appeal when considered in detail, as is now evident. We would suggest that if re-evaluated with the information now available (including that provided in this response) the perceived benefits of ROs would be heavily outweighed by the additional complexity associated with their implementation and the risks and consequent costs they generate for participants and consumers, particularly under the current project timetable. On the latter note, we understand that delivery of ROs in Italy has been significantly delayed because of complexities in introducing the scheme.

We also observe that reforms are ongoing in other markets that have ROs with fundamental changes being implemented to the ISO-NE scheme which is heavily referenced by the RAs to inform the I-SEM design. It is highly pertinent that said reforms in ISO-NE, as informed by the NERA report, include a proposal to eliminate the Peak Energy Rent (PER) adjustment (i.e. the payment back to the system in circumstances where the market prices exceed the defined strike price) in conjunction with the pay-for-performance reforms.

It is further instructive to note that GB decided against ROs, having considered them, for the following reasons[6] which resonate with the concerns we substantiate in this response:

*"…there are a number of drawbacks [with ROs]:*

- *While there may be some scope to provide for consumers who suffer blackouts to receive some compensation, this model offers less assurance that blackouts will be prevented – that is, there would be no checks to ensure that capacity providers have sufficient capacity and will be available when required.*

[6] See 'Electricity Market Reform: policy overview – Annex C', paragraph 71, published by DECC in November 2012.

- *The potential level of liabilities that providers are exposed to are in effect "uncapped" – which could increase the risk to which holders of capacity agreements are subject, increasing participants' costs and therefore the overall costs of the Capacity Market.*
- *This model may have a greater impact on liquidity in the forward electricity market as capacity providers may seek to hedge the risk they are exposed to in the Capacity Market by selling electricity in the reference market".*

Given the strictures of State Aid approval that will apply to the scheme in I-SEM a prudent approach should be taken as further reforms at a later date (for example to eliminate the CfD aspect of the scheme as ISO-NE is doing) may be difficult and lengthy to implement.

Energia would suggest that consideration be given to implementing a 'GB style' capacity mechanism rather than the proposed RO approach. A move to a 'GB style' capacity mechanism would significantly reduce the complexity of the CRM design by simplifying its interactions with the energy market, and, in so doing, substantially reduce the implementation risk for the project. We also note that the GB mechanism has achieved State Aid approval which is a helpful precedent for I-SEM.

## *2.2 Interaction between ROs and the I-SEM forward market*

ROs are effectively a centrally administered energy contract with a 'bolt on' capacity mechanism (e.g. a capacity requirement, eligibility criteria, physical backing, performance incentives, etc.). The design of the energy contract component (the reliability option) used in an RO scheme therefore has the potential to impose significant commercial risks on participants (e.g. basis risk) that could significantly impact wider energy market dynamics. It therefore requires very careful consideration. A further cause for concern is that the energy contract component occupies the same market space as normal forward energy contracts (e.g. 2 way CfDs) that under an RO scheme remain essential for generators and suppliers to manage commercial risks. This latter issue is particularly problematic in the context of the I-SEM, given the liquidity issues already prevalent in the SEM forward contract market.

Careful consideration therefore needs to be given to the interactions between ROs and the I-SEM forward contract market to ensure the design of reliability options does not interfere with, or destabilise, the normal operation of the I-SEM forward contract market. Such an outcome would undermine the risk management activities of participants, is likely to increase commercial risk premiums on trading activities, and would therefore result in a direct increase in costs to consumers. In our response to the detailed questions in section 3 below we have offered recommendations to help reduce these risks but they are unlikely to eliminate them.

Furthermore Energia maintains that the implementation of ROs reinforces the requirement for an exchange based approach to forward contract trading under I-SEM. Such an approach would facilitate the central development of a standard CfD contract via the Forwards and Liquidity workstream (bilateral negotiation of contract terms can be onerous and extremely time consuming) to try to minimise any potential and unnecessary contractual barriers to liquidity in the forward contract market generated due to the implementation of an RO scheme. The implications of grandfathering and multi-year ROs also need to be carefully considered as discussed in our answer to the question on that topic in section 3 below.

## *2.3 Strike price*

Energia does not support a floating strike price and recommends a high, static strike price is set for ROs to minimise their potential impact on the I-SEM forward market and to facilitate effective grandfathering (i.e. to avoid the strike price having to change). We suggest the strike price should be set as a % VOLL (e.g. 50% of VOLL subject to the value set for VOLL) to ensure ROs are not triggered other than in a scarcity event and not by changes in the cost bases of CRM units. A detailed description of our proposals and the rationale behind them is provided in this response.

## *2.4 Choice of reference market*

We believe referencing ROs to any other market than the day-ahead market could cause significant liquidity issues in both ex-ante spot and forward contract markets due to basis risk. The likely effect of ROs will be to incentivise liquidity in the market they are referenced to and therefore the only sensible reference market, within the context of the stated rationale for the I-SEM energy market design, is the day-ahead market.

## *2.5 Scheduling and dispatch risk*

Energia observe that the considered load following adjustment to ROs do not account for scheduling / dispatch risk under an RO scheme. While a high strike price may help mitigate this risk, it will not remove it. RO obligations should therefore be reduced in proportion to generation schedules / dispatch subject to bidding behaviour and CRM unit availability. We make more detailed recommendations regarding this in the response. If this approach is not adopted then the associated commercial risk would have to be reflected in the capacity price to ensure the full recovery of "missing money", and would therefore increase costs to consumers. These potential risks increase as the strike price for RO decreases. Implementing the necessary exemptions, however, may lead to a shortfall in the balance of payments that undermines the efficacy of the supplier hedge.

## 2.6 Hole in the hedge

Energia sees the 'hole in the hedge' under ROs a major issue. To maintain a 100% hedge level on the demand side (suppliers) consumers will have to fund any shortfall in payments between revenues collected from RO contracted generation and difference payments made to suppliers (e.g. sue to ineligibility, out of contract generation, exemptions, etc.). This effectively removes the cap on consumer prices provided by ROs, undermining one of the original perceived benefits of the mechanism.

## 2.7 Profiling of option fees from suppliers

It is difficult to understand how profiling of option fees could be introduced for suppliers in the absence of similar profiling on generator receipts, without opening up a large imbalance of payments that would need to be funded raising the overall costs to the consumer. The introduction of sculpting of payments / receipts in relation to the option fee however undermines the benefit of introducing an RO based CRM scheme in the first place (i.e. the hedge of volatility in market prices). The extent of this issue depends upon the methodology used to profile capacity receipts / payments and the value set for the RO strike price. On the other hand, not to sculpt the supplier payments would undermine the demand side signal under an RO scheme. Energia cannot identify a particularly attractive solution to these issues but considers, on balance, that minimal profiling in conjunction with a high strike price, or a flat charge to suppliers, at least for the option fee component of the capacity charge, is the only approach that seems consistent with the intent of the RO.

## 2.8 Credit cover

Energia would emphasise the need for a properly collateralised I-SEM energy and capacity market, but request that the overall credit requirements placed on participants are optimised to ensure sufficient collateralisation is achieved with minimum overhead. Such an approach will ease the credit burden for existing participants, ensure excessive credit requirements do not become a barrier to new entry, and lower costs for consumers. We have set out a number of suggestions on how this could be achieved in our answer to the question on credit cover arrangements for the CRM. Energia would further observe that careful consideration needs to be given as to whether the increased collateralisation required by an RO scheme is warranted, compared to a 'GB style' mechanism, which would be significantly less credit intensive because of the absence of an energy contract component.

## 2.9 Performance incentives

The balancing market price is the main incentive to provide energy at times of system stress. Therefore discussion of performance incentives under the CRM should be conducted with reference to the likely incentives provided by the balancing market, and in particular the approach to imbalance pricing. To the extent that the balancing market is sufficient to incentivise delivery of capacity at times of system stress, the need for additional performance incentives is reduced. The appropriateness of delivering incentives to generate via the balancing market however, rather than through the imposition of performance incentives linked to the CRM scheme, depends on the wider energy market dynamics, and, in particular, the ability of participants (especially suppliers) to manage their exposure to volatile balancing market prices (e.g. scarcity pricing). Therefore the debate on performance incentives is directly linked to the debate on imbalance pricing (including scarcity pricing), which in turn, is linked to the debate on the likely dynamics of the wider energy market design (e.g. liquidity levels in ex-ante timeframes including the forward contract market). It is therefore important that consideration of performance incentives is conducted within this wider context.

Energia observes that the need for performance incentives, discussed in the consultation paper, and evidenced by the experience of RO schemes in other countries, indicates that the RO itself has tended to be ineffectual in delivering appropriate incentives for delivery of capacity and energy at times of system stress. Furthermore, any attempt to increase incentives under the RO (e.g. lowering the strike price, which we note is an approach ISO NE has conclusively elected not to adopt) further complicates their already problematic interactions with the functioning of the wider energy market. Given the substantial issues associated with the implementation of ROs, identified in the consultation paper and discussed in this response, it therefore remains unclear why they have been selected as the CRM scheme for the I-SEM, particularly given the already challenging timeframes.

Furthermore, as a general principle, Energia would again emphasise that it is important the I-SEM does not impose unmanageable commercial risks on participants, otherwise there is an increased risk of market failure. Given the complexity of introducing performance incentives, and its significance for the success of the I-SEM, we therefore recommend that a workstream is set up to determine an appropriate enforcement regime under the CRM scheme, within the context of the wider I-SEM energy market design. We make further detailed recommendations in relation to performance incentives in our response to the consultation questions on that topic.

## *2.10 Scarcity pricing*

Managing exposure to scarcity pricing should primarily be via energy trading in the ex-ante energy markets not via a centralised RO scheme referenced in some way to the balancing market. As discussed, referencing ROs to the balancing market, will impose unnecessary basis risk on generators, undermining liquidity in ex-ante markets, while the strike price for ROs, which is likely to have to be high to avoid other complications (e.g. scheduling / dispatch risk), will not provide an adequate hedge for suppliers during scarcity events. The issue of scarcity pricing therefore needs careful consideration in the context of the wider energy market and must consider imbalance pricing arrangements, as well as likely liquidity levels in the forward contract, day-ahead and intra-day markets. Energia cautions that these are extremely complex, difficult issues, with serious consequences for participants and I-SEM consumers. They therefore require substantial further careful analysis and consideration.

We find it unhelpful that the discussion of such issue has been parachuted into the CRM workstream and has not, to date, been properly debated as part of the energy trading arrangements, and we therefore recommend that scarcity pricing, moving forward, is primarily dealt with under the ETA workstream. Furthermore, there is the risk that the current approach to debating scarcity pricing may not promote proper consideration of its implications on wider energy market dynamics, including participant risk management, as there is currently an unwarranted assumption that ROs can provide suppliers with a sufficient hedge against scarcity pricing (which is subject to the level of the RO strike price, the reference market and the implications decisions on these have for trading incentives under the energy market arrangements). Energia therefore has concerns that potentially important issues, such as those set out above, may not be properly considered.

## *2.11 Eligibility*

In principle all plant that is capable of contributing capacity to the system should be considered eligible to participate in the capacity mechanism, including renewables receiving support through government renewable support schemes – we support the IWEA position in this regard.

The consultation paper refers to longer term ancillary service contracts and notes the importance of not overcompensating recipients of such contracts through the CRM. It is not entirely clear what this refers to as DS3 system service products (as currently defined) do not reward the provision of capacity and are not paid on the basis of availability.

Mandatory participation in the RO would be problematic for wind given the risks of participation. Furthermore if additional penalties are included in the RO design, then it would appear to presuppose a discretionary requirement on the part of all providers, allowing parties to evaluate the implications of such penalties in their decisions.

Energia recommends that conventional, non-firm generation, is eligible to participate in the capacity market, but at its own risk (i.e. without exemption from RO pay outs or penalties under performance incentive schemes), with a de-rating factor based upon a projection of the unit's likely transmission system access during system stress events (i.e. Option 2 as presented in the consultation paper). To avoid barriers to new entry, Energia would however advocate that generators, whose firm access has been delayed due to factors beyond their control, should be granted "deemed firm access". As a general comment Energia would stress that the implementation of the current firm access policy under the I-SEM energy and capacity trading arrangements requires further urgent clarification. In particular, how firm access and compensation for transmission constraints will be implemented in the I-SEM balancing market for participants that do not hold ex-ante contract positions.

## *2.12 De-rating*

Energia recommends a plant specific approach to de-rating is adopted to maintain incentives on CRM units to improve availability and therefore deliver a more efficient outcome for consumers. It also ensures more equitable treatment for CRM participants given the reasonably large discrepancies in the performance of units with technology segments to ensure those units with higher than average availability are properly rewarded under the scheme.

Energia recommends an historic approach to de-rating (based upon an objective formula based approach), but acknowledge that, in practice, a hybrid approach may be required in exceptional circumstances to account for new build or major refurbishment, subject to robust governance and appropriate oversight to safeguard the integrity of the CRM scheme is maintained. Energia requests that the option to implement a generator testing regime (to eliminate "ghost capacity" under the CRM) is consulted upon but emphasise it would have to ensure full cost recovery by the generator and carefully consider interaction with TSO incentives around dispatch balancing costs. Energia recommend that this area is further considered and debated via the working groups proposed in this response.

Energia recommends an approach to grandfathering of de-rating factors that provides a degree of certainty for investors, while maintaining incentives on holders of long term capacity contracts to improve availability. The approach should also provide a mechanism whereby the capacity market can readjust for under performance against agreed benchmarks for long-term capacity contract holders. We also note that a different approach may be required for conventional units compared to intermittent renewables. We make specific recommendations regarding this area in section 3 of this response.

## *2.13 Capacity requirement*

We note the SEM Committee's minded to position not to change the security standard from its current level of 8 Hours LOLE. However, this is not the standard evidently targeted in practice and is not plausible given the tighter standard of 4.9 Hours LOLE that applies in Northern Ireland. We suggest formalising the standard that is currently targeted in practice which is more akin to a level of 3 Hours LOLE consistent with GB and France. We would further note customers and industry on the island of Ireland have become accustomed to a high level of reliability. If the intention and effect of I-SEM is to aggressively sharpen exit signals it is important that policy makers are prepared to accept the security standard chosen and put in place system operation protocols consistent with this.

The consultation paper states that it will be necessary to reduce the quantity of capacity required through the auction to account for that which does not need to be procured – i.e. the sum of the "de-rated" capacities of the plant which is ineligible or chooses not to bid. Whilst we can understand the principled rationale for this not to procure more capacity than is required to meet the defined security standard; special consideration should be given to the treatment of wind as outlined in the IWEA response – they propose an option to assign wind a capacity value outside the RO mechanism. Secondly, it is not correct that capacity should be de-rated the same whether it participates or not in the capacity mechanism as participation brings with it performance incentives (whether through the RO or other incentives) and therefore non-participating capacity should be de-rated more for the purpose of the capacity requirement adjustment. Thirdly, the risk of exit by non-participating capacity (either through ineligibility or choice) should be given due consideration.

Careful consideration should also be given to the treatment of capacity providers with long term capacity contracts that are outside the CRM (both in terms of eligibility to participate in the auction and the capacity requirement adjustment) to ensure the market is not distorted by such interventions – this does not seem to have been considered in the consultation paper. For example as Poyry point out in their report, when SONI awarded a three year capacity contract to AES in 2014 to help meet an anticipated shortfall in capacity in Northern Ireland in the coming years no attempt was made to isolate the effects of this intervention on the energy or capacity market.

## *2.14 Exit signals*

Customers and industry on the island of Ireland have become accustomed to a high level of reliability. If the intention and effect of I-SEM is to aggressively sharpen exit signals it is important that policy makers are prepared to accept the security standard chosen and put in place system operation protocols consistent with this as explained in section 3 of this response.

It is also important to consider at this stage the necessary arrangements to secure capacity in constrained locations that is required for system security reasons but does not receive sufficient revenues through the market. This has not been considered to date and is a material oversight given the level of constraints on the system and the risk of inefficient exit signals resulting from

I-SEM which is an unconstrained market. It is urgent to consider this now given the potential that any solution may require state aid clearance. It was raised at the Senior Stakeholder Forum on 15 May this year and was reflected in subsequent EAI feedback to the SEM Committee on 28 May but still no visible action has been taken to address it, which is a concern.

In the event that exit signals are appropriately received by plant, it is imperative that the obligations placed on that plant (for instance through its generation licence or the Grid Code) allow exit in the same timeframe as the signal given by the market. This was agreed as being necessary by the RAs at the May forum.

## *2.15 Implications of SEM-15-14 for the RO design*

Energia would note that long term stability in the regulatory environment is an essential component of promoting liquidity across I-SEM markets. Perceived regulatory risk in the SEM / I-SEM will undermine investment and discourage forward contracting by introducing uncertainty regarding the commercial risks associated with entering into longer term transactions. The 'minded to' Decision SEM-15-14 of the SEM Committee on 'Outturn Availability' is a recent example of this kind and could, if implemented, act as a further barrier to forward market liquidity because of the implicit changes to the SEM firm access policy that results in increased commercial risks for generators when transacting forward. Under I-SEM this increase in commercial risk is likely to be translated into an increase in the offer prices submitted into capacity auctions. We would thus encourage the SEM Committee to re-consider this 'minded to' Decision in light of its wider negative consequences. Considering the implications of SEM-15-14 for the RO design, NERA[7] have provided the following assessment:

*"The approach to exemptions and caps on penalties in the I-SEM capacity mechanism takes on added significance due to the recent introduction of a provision allowing TSOs to re-declare the achieved capacity of a generator at the level of their effective availability during network outages. This proposal exposes generators who participate in the RO to the risk of network operations, over which they have no control. We see three possible methods for managing this proposal within the RO scheme:*

*1. pass through of the implications to suppliers and consumers, i.e. give explicit exemptions from penalty on those occasions where the TSO re-declares plant availability due to a network outage;*

*2. pass the penalty over to the TSO, i.e., make the TSO liable for the penalty payments incurred by the plant due to its network outages; or*

[7] NERA, 14 August 2015, 'The Capacity Remuneration Mechanism in the I-SEM – Detailed Design', page 27.

*3. leave the risk with capacity providers and require them to manage the risk as best they can.*

*In circumstances where capacity providers have no control over the network outage, placing the risk on capacity providers does not provide any sharper incentives but threatens them with potential financial problems and even bankruptcy. The most efficient outcome is likely to be a combination of all three possible methods, but with the main emphasis on method 1 (because the event should be objectively identifiable), perhaps some reliance on method 2 (if there are cases where it makes sense to maintain incentives, within limits) and very little use of method 3 (because it imposes risk but offers little or no improvement in incentives)".*

## *2.16 Treatment of de-minimus generation*

Given the marked complexity of I-SEM and the increased costs and risks of participation that are envisaged compared with SEM, Energia agrees with the SEM Committee's previously communicated position not to preclude the retention of a de-minimis level below which generation can be registered as 'negative demand' and to furthermore allow for gross portfolio bidding from generation in certain circumstances, specifically for small variable generation. This will facilitate the current treatment of de-minimis generation at the current threshold of 10MW which is appropriate and effective and will also enable the continued provision of intermediary (or aggregation) services by suppliers. We note that a question was asked in the workshop on 31 July 2015 if supplier charges would continue on the basis of net demand. The response to this was "yes, working to the principle of only changing things if necessary". We support this position.

## *2.17 Next steps*

Energia would welcome further dialogue with the RAs on the issues raised in this response. In particular, how the commercial risks and credit requirements imposed on CRM participants will be minimised (to reduce the overall cost of the scheme for consumers); how the impact of ROs on liquidity in the forward market will be minimised; and how the CRM design could be simplified to substantially reduce the implementation risks for the project.

For reasons discussed above we would urge the SEM Committee to re-evaluate the merits of moving forward with ROs for I-SEM at this stage, before expending further scarce resources and time on their design, and would suggest that a GB type scheme would be worthy of consideration.

More generally we would welcome further engagement with the RAs and their advisors on the development of the capacity mechanism for I-SEM. The industry workshops to date have been useful and the approach pragmatic, and Energia welcome the openness of the CRM project team to explore and discuss difficult implementation issues and make changes to project timings to help facilitate their resolution. For example deferring the first auction to June 2017 and presenting 'Emerging Thinking' at the next industry workshop on 28 September are welcome developments. We note that the decision from this consultation is expected to be published in November without going to a proposed decision however. Energia would stress the importance of publishing a proposed decision so that there can be further opportunity for input at that stage. At the same time there is a need for more detailed stakeholder engagement on key issues highlighted in the NERA report and in this response.

As NERA have suggested in their report, the design of the CRM would benefit from further industry input in the following areas:

- on the implications of particular strike prices and MRPs for risk and liquidity, organised as a workstream on pricing;
- on the technical and plant-level data to be used in CRM formulae, organised as a workstream on capacity definitions; and
- on the economic and financial parameters used to define and limit rewards and penalties for providing capacity, organised as a workstream on enforcement. (We would emphasise that this workstream also needs to also carefully consider the implications of performance incentives within the context of wider market power concerns in the I-SEM.)

Energia stress that the design of an incentive mechanism requires careful consideration and further detailed debate with stakeholders (via working groups) to ensure the incentives introduced under the CRM scheme are appropriate, in the sense of not exacerbating market power concerns, and not unduly penalising participants who cannot modify their behaviours, which would simply impose unmanageable commercial risks on some eligible CRM participants. It is therefore important that exemptions rules are considered (e.g. for intermittent generation, or generation subject to scheduling / dispatch risk, etc.), as well as the need for caps and floors. We discuss both of these in more detail in our answer to later questions.

In addition there is a need for further input from industry on credit cover and collateral requirements and it is worth noting in passing that ROs could significantly increase the burden on participants relative to other schemes. We would suggest a dedicated working group to consider these issues across all I-SEM and DS3 markets and timeframes to ensure that the overall credit requirements placed on participants is optimised, providing sufficient collateralisation whilst minimising credit cover requirements. Such an approach will ease the credit burden for existing participants, ensure excessive credit requirements do not become a barrier to entry, and lower costs for consumers.

Noting the complexity associated with taking investment decisions Energia would also recommend that there is further debate with stakeholders on pre-qualification requirements, implementation agreements, and pre-commissioning phase performance incentives to help ensure proper consideration of all of the issues, given the importance of generating the market conditions required to deliver new investment into the I-SEM in the future. This again is best accommodated via working groups organised to cover these areas.

# 3. Response to Consultation Questions

This section of our response provides feedback to the specific questions asked in the consultation paper. It should be read in conjunction with our general comments and the accompanying NERA and Poyry Reports.

It is difficult to be definitive in response to some of the questions at this stage with so much uncertainty and given the complexity in the RO design and its interaction with the energy market design and forward contracting. The next steps we have suggested in section 2 above would help alleviate these difficulties.

## *Chapter 2: Capacity Requirement*

**A) Feedback on our minded to position to retain the all-island security standard of 8 hours LoLE.**

The all-island market has a track record of paying for an 8 hour LOLE standard but then achieving a 3 hour standard through other means. It is also the case that Northern Ireland's tighter security standard of 4.9 hours LOLE means that the all-island reliability is better than 8 hours. A detailed validation of these points is provided by Poyry in their June 2015 report for the Electricity Association of Ireland and is submitted along with this response.

As Poyry state *"…it is not realistic that the all-island unconstrained GSS could drop below 4.9 hours at equilibrium"*. Even when the Northern Ireland standard of 4.9 hours lost load was exceeded by more than 200MW in the 2014 GAR a market intervention was initiated to ensure greater security of supply resulting in the award of a 3 year capacity contract to AES. Poyry conclude that *"[o]n average a significantly more cautious approach to system security appears preferred such that the average targeted LOLE across years is materially less than the GSS [standard of 8 hours LOLE]"*[8].

The security standard should align with that targeted in practice, which is evidently less than 4.9 hours and more akin to a 3 hour standard. The analysis interpreted in SEM-15-044 justifying no change to the security standard from its current level of 8 Hours LOLE is therefore invalid unless this is the standard applied in practice and the system operators are prepared to target a lower security standard than they currently do and put in place system operation protocols consistent with this. In extremis this means:

a) Customers in Ireland being disconnected before customers in Northern Ireland (as implied by a 4.9 hour standard in NI); and
b) Exporting to GB when customers are being disconnected on the island of Ireland (as implied by a 3 hour standard in GB).

[8] Poyry Management Consulting, June 2015, 'Review of Consultation on Proposed Annual Capacity Payment Sum for 2016', page 8.

Before arriving at a final decision on the most appropriate security standard to apply in I-SEM, consideration should also be given to the following points which would suggest formalising the standard that is currently applied in practice which is more akin to 3 hours LOLE:

- It is important to ensure consistency with neighbouring countries GB and France which have adopted a 3 hour standard to ensure inward investment and economic competitiveness. Note that 'perceived' reliability of supply is critical, thus economic competitiveness is likely to be affected even if a tighter standard is maintained in practice.
- Adopting a coordinated regional adequacy standard is consistent with the wider EU framework and market integration as advocated by the European Commission in its recent Summer Package. On this note EirGrid and SONI point out in their June 2015 report to the SEM Committee[9], *"As Ireland and Northern Ireland are already using similar assessment methodologies to those used in Great Britain and France, applying a coordinated regional generation adequacy standard is arguably a prudent next step …DECC has selected an adequacy standard of 3 hours LOLE to be used in Great Britain. France also uses an adequacy standard of 3 Hours LOLE"*.
- Adopting an 8 hour LOLE standard implies a 'constrained' LOLE expectation of materially more than 8 hours which may not be acceptable to the system operators in what is a highly constrained system.
- The consequences of an 8 hour security standard should be carefully considered in the context of moving to a quantity based capacity mechanism and EU requirements that capacity procured through a CRM should be consistent with the defined security standard.
- Customers and industry on the island of Ireland have become accustomed to a high level of reliability. If the intention and effect of I-SEM is to aggressively sharpen exit signals it is important that policy makers are prepared to accept the security standard chosen and put in place system operation protocols consistent with this as explained above.
- Adopting an 8 hour standard for the capacity auction will increase the likelihood of further distortionary and costly market interventions associated with maintaining a tighter standard in practice given the demonstrated desire and tools of the system operators to act to raise the security standard above that required to meet an 8 hour all-island LOLE.

[9] EirGrid/SONI, June 2015, 'Options for the Capacity Adequacy Standard in the I-SEM', page 6.

**B) Comments from respondents as to their preferred method of accounting for unreliability of capacity in determining the capacity requirement, along with reasons behind their preference.**

The CRM has two elements:

The first is the capacity requirement, i.e. the *demand* for capacity. This amount is set for the market in total and should be defined by a mechanistic formula that uses publicly available data that cannot be manipulated.

The second element is the amount of capacity available at each plant, i.e. the *supply* of capacity. That should be defined for each plant and we are suggesting (see our response to question 4C) that it should use each plant's nameplate capacity (correctly defined) de-rated on the basis of its own historical performance. As in the first case, this de-rating would use a fixed formula that did not allow for the value to be manipulated.

The consultation paper is suggesting that the capacity requirement (demand for capacity) should be de-rated to account for plant unreliability and that this should be done on the same basis as de-rating eligibility to supply capacity. It then seems to betrays a pre-disposition towards technology specific de-rating factors which raises concerns that the outcome may be pre-determined, i.e. "The defined fraction would vary by capacity type – reflecting its typical reliability, and hence its impact on the total nameplate requirement for capacity" (SEM-15-044, page 21).

We are in favour of de-rating *eligibility for the supply of capacity* but on a plant-specific basis (with few qualified exceptions, e.g. for wind) as generic de-rating removes incentives to improve performance and the all-island market has a high concentration of the same technologies (as discussed further in our response to question 4C).

Following the discussion above we would be concerned that generic de-rating factors are utilised to determine eligible capacity as this is not the right solution; and secondly we would stress that de-rating adjustments to the capacity requirement should use a fixed formula that does not allow for the value to be manipulated.

In summary we favour a de-rated capacity requirement (based on plant-specific de-rating factors) using a fixed formula that is transparent and that cannot be manipulated.

**C) Feedback on the options presented in relation to accounting for demand forecast uncertainty, along with rationale behind any position.**

- Accounting for demand forecast uncertainty is a probabilistic exercise that should ideally be supported by stochastic modelling.

- Recognising that stochastic modelling may not be viable at this stage a prudent approach should be taken based on a worst case scenario methodology given the consequences of a high impact low probability event on a small system and the blocky nature of power sector investment rendering a small market particularly sensitive to entry or exit decisions of generation given the indivisibility problem (one of the reasons for requiring a capacity mechanism in the all-island market).
- The optimal scenario approach is not considered appropriate for reasons inverse to supporting the worst case scenario methodology – i.e. it could result in forecast demand that is less than prudent given the small size of the all-island system. It is also less transparent and its outcome is highly sensitive to the scenarios chosen and the VOLL assumption.

In summary, ideally demand forecast uncertainty should be accounted for using stochastic modelling. Until this is viable a 'worst case scenario' methodology is the prudent approach that should be taken given the small size of the all-island system and the blocky nature of power sector investment. The optimal scenario method should not be implemented because it is potentially less prudent, less transparent and its outcome is highly sensitive to the scenarios chosen and the value of VOLL.

**D) Feedback on our minded to position to base the capacity requirement for the CRM on a single capacity zone**

- We support the minded to position (for reasons cited in the consultation paper) to base the capacity requirement and CRM auction on a single capacity zone. However, for reasons stated in our response to question 2A above, it is not realistic to have a security standard of 8 hours LOLE for the island of Ireland and a standard of 4.9 hours for Northern Ireland. We suggest that the capacity requirement for the single zone all-island market should therefore be determined with reference to a security standard of 3 hours LOLE in line with that targeted in practice and consistent with the neighbouring market that we are interconnected to.
- We also agree in principle that to introduce a further locational signal would introduce a level of complexity which would be challenging to achieve within the current I-SEM programme. Other areas of complexity associated with implementing Reliability Options should be evaluated given the aggressive implementation timescale. It is important to point out however that the current locational signals in the form of TLAFs cannot be ignored and need to be accounted for in the capacity mechanism consistent with the energy trading arrangements.
- Whilst we agree that a single zone for the capacity market is appropriate it is important to consider at this stage the necessary arrangements to secure capacity in constrained locations that is required for system security reasons but does not receive sufficient revenues through the

market. This has not been considered to date and is a material oversight given the level of constraints on the system and the risk of inefficient exit signals resulting from I-SEM which is an unconstrained market. It is urgent to consider this now given the potential that any solution may require state aid clearance. It was raised at the Senior Stakeholder Forum on 15 May this year and was reflected in subsequent EAI feedback to the SEM Committee on 28 May but still no visible action has been taken to address it, which is a concern.

**E) Detail of any other considerations respondents felt that we should take account of when determining the capacity requirement for the CRM.**

- We would refer to the principle of transparency espoused in the NERA report that the capacity requirement should be defined by a mechanistic formula that uses data on demand and reserve requirements taken from published sources that cannot be manipulated. There should only be one capacity requirement calculation and it should meet these minimum standards of transparency. Currently there are two calculations that do not align and that are difficult to replicate, the GAR and capacity requirement used for the CPM.

- The consultation paper states that it will be necessary to reduce the quantity of capacity required through the auction to account for that which does not need to be procured – i.e. the sum of the “de-rated” capacities of the plant which is ineligible or chooses not to bid. Whilst we can understand the principled rationale for this not to procure more capacity than is required to meet the defined security standard; special consideration should be given to the treatment of wind as outlined in the IWEA response – they propose an option to assign wind a capacity value outside the RO mechanism. Secondly, it is not correct that capacity should be de-rated the same whether it participates or not in the capacity mechanism as participation brings with it performance incentives (whether through the RO or other incentives) and therefore non-participating capacity should be de-rated more for the purpose of the capacity requirement adjustment. Thirdly, the risk of exit by non-participating capacity (either through ineligibility or choice) should be given due consideration.

- Whilst demand side participation may be a national and EU policy objective its contribution to capacity adequacy should not be over-stated. We would refer to the NERA report which provides a useful discussion of this issue.

- Careful consideration should be given to the treatment of capacity providers with long term capacity contracts that are outside the CRM (both in terms of eligibility to participate in the auction and the capacity requirement adjustment) to ensure the market is not distorted by such interventions – this does not seem to have been considered in the consultation paper. For example as Poyry point out in their report, when SONI awarded a three year capacity contract to AES in 2014 to help meet an anticipated shortfall in capacity in Northern Ireland in the coming years no attempt was made to isolate the effects of this intervention on the energy or capacity market.

- Whilst we agree that a single zone for the capacity market is appropriate it is important to consider at this stage the necessary arrangements to secure capacity in constrained locations that is required for system security reasons but does not receive sufficient revenues through the market. This has not been considered to date and is a material oversight given the level of constraints on the system and the risk of inefficient exit signals resulting from I-SEM which is an unconstrained market. It is urgent to consider this now given State Aid considerations. It was raised at the Senior Stakeholder Forum in May this year and was reflected in subsequent EAI feedback but still no visible action has been taken to address it, which is a concern.

## *Chapter 3: Product Design*

### A) The approach to setting the Reliability Option Strike Price:

**a. Should we adopt the "floating" Strike Price approach, which is indexed to the spot oil or gas price?**

Energia do not believe a floating strike price is an appropriate approach but agree that the RO strike price should be set at a sufficiently high level to exclude the possibility of an RO being triggered other than during a scarcity event, to minimise complications regarding the interactions with the forward contract market (discussed further below), and the functioning of the option mechanism itself, including scheduling / dispatch risk and issues associated with load following (again discussed further below and in subsequent answers to consultation questions). The RO strike price should therefore be targeted at hedging only a portion of scarcity rents for suppliers and not commodity risk. The forward contract market should remain the primary trading mechanism through which risk is managed (i.e. commodity risk and any residual exposure to scarcity rents due to the level of the RO strike price).

Energia therefore recommends that the strike price for ROs is set at a level that ensures it is extremely unlikely to be triggered other than in scarcity events – e.g. 50% of VOLL subject to the value set for VOLL. The methodology used to set the strike price should confirm that spikes in commodity pricing or large movements in FX are unlikely to lead to the triggering of RO payments. Leaving aside the issue of scheduling / dispatch risk, discussed in more detail in our answer to later questions, if the RO strike price is not appropriately defined then payments under ROs could be triggered during periods when not all generation is scheduled. This would result in an exposure for unscheduled generators, significantly increasing the commercial risk associated with participation under the scheme. This additional commercial risk would then need to be reflected in capacity pricing, increasing costs to consumers. This risk, however, could be difficult to price into capacity offers, and could undermine the recovery of "missing money", and therefore the overall efficacy of the scheme as a capacity mechanism.

**b. How do we choose the reference unit? Should it be based on actual plant on the system or a hypothetical best new entrant (BNE) peaking unit as currently used for setting the Annual Capacity Payment Sum?**

As the strike price set for reliability options decreases the commercial risk imposed on generators increases, amongst other reasons, because ROs may get called when generators are not scheduled. This increase in commercial risk will manifest itself as a premium to the capacity price and therefore an additional cost to the consumer. A floating strike price also undermines the efficacy of the RO hedge for the supply side as the price cap moves day to day with changes in the cost base of the reference generator. While this can, in theory, be managed with hedging CfDs a floating strike price could further complicate contractual arrangements and makes generator's forecast of pay outs under ROs more complex. It also creates issues for grandfathering which are discussed in more detail in our answer to the question below. Energia therefore does not support either a hypothetical unit approach or a BNE type approach to setting the strike price and rather recommends that the strike price for ROs is set at a stable, high level (e.g. 50% of VOLL depending on the value attributed to VOLL).

In setting the strike price for ROs (i.e. the % of VOLL) analysis should be completed to ensure that the price is significantly higher than the operating costs of the most expensive I-SEM unit that could be scheduled / dispatched in a scarcity event. It must be significantly higher to provide a buffer against changes in cost base to ensure the strike price for ROs is unlikely to need to change in the future. This analysis therefore needs to account for potential changes in commodity prices, FX, gas capacity costs, etc. over time, or dispatch below MSG in the case of referencing ROs against the DAM (the scheduling in the DAM does not necessarily respect generator technical feasibility).

If the BM is set as the reference market for ROs the methodology for calculating the maximum likely operating cost of a unit in the I-SEM should be determined by spreading the operating costs of each I-SEM unit at min gen across its minimum on time (including its start-up, no load and maximum gas capacity costs). In the DAM, as it does not respect technical characteristics, and given a generator with a MIC could be scheduled for a single period, this calculation should be carried out over a single hour. Once the maximum operating cost is identified a significant cost buffer should be added to future proof the analysis. This should then be used to determine the appropriate % of VOLL used to set the RO strike price.

Maintaining a static strike price should help facilitate effective grandfathering of strike prices (because the strike price will not change) without causing unnecessary complexity in the functioning of the forward market. This is discussed in more detail in our answer to the question below.

**c. Should we grandfather this reference unit where a multi-year RO is sold by new capacity?**

As discussed in our answer to the question above we do not believe the strike price should be referenced to a unit, hypothetical or otherwise but should be set at a static level. Grandfathering of the strike price would seem to be problematic for the operation of the forward contract market unless such an approach was adopted. Grandfathering would otherwise mean that in any contract year more than one strike price could be in operation and this could undermine the functioning of the forward contracts market. This is because a generator with a grandfathered strike price could only make difference payments on a 2 way CfD up to the level of its specific RO strike price otherwise it would have a double exposure if an RO was called. A supplier on the other hand (who bought the hedge) may only receive payments under ROs at the strike price used by the majority of the market (which could create a ‘hole in their hedge’) unless there was some form of tagging between ROs and forward contracts which would seem complicated to introduce. While the issue may be solvable it seems likely to either result in a ‘hole in the hedge’ for the supplier, an exposure for the generator or a balance of payments issue that needs to be funded by the consumer. None of these options seems favourable and with the exception of the latter, which imposes additional costs on the consumer, will undermine the proper functioning of the I-SEM forward market, and therefore the ability of participants to adequately hedge.

On the other hand, not to grandfather the strike price increases participation risk for new entrants increasing the cost of capacity. If this risk is substantial it could act as a barrier to new entry undermining the efficacy of the mechanism.

**B) The implementation of scarcity pricing in the I-SEM Balancing Market?**

Scarcity pricing would seem to be an issue that is best dealt with under the ETA workstream and needs to be considered in relation to the wider energy market arrangements. The purpose of scarcity pricing is to ensure that the full costs of balancing the system are represented in the balancing market price, not to make generator incentives under ROs work (which seems to be the suggestion in the consultation paper). We would also note that scarcity pricing is only relevant to the debate on ROs if ROs are referenced to the balancing market price, as scarcity is predominantly a feature of the real time market. Please note that we do not think the balancing market is a feasible option as the reference price for ROs. This is discussed in more detail in our answer to the next question.

Managing exposure to scarcity pricing should primarily be via energy trading in the ex-ante energy markets not via a centralised RO scheme referenced in some way to the balancing market. This is because such a centralised RO scheme, depending on how it is set up, changes the balance of risks between the supply (in the sense of generation) and demand sides of the market. On the demand side, introduction of an RO struck against the balancing market price would actually weaken incentives to self-balance (subject to the level of the strike price), but if the RO strike price is set high suppliers (the demand side) are then left without an effective hedge to scarcity pricing under the RO, and are therefore reliant on their ability to trade through ex-ante markets. Note, again, subject to strike price, trading incentives / penalties are also potentially doubled up on the supply (generation) side. If a CRM unit with an ex-ante position trips during a period of system stress then they are potentially exposed to the balancing price and the RO cash out, if ROs are referenced to the balancing market. Introducing scarcity pricing under such a scenario (which is likely to increase the RO cash out subject to the level set for the strike price) could therefore undermine incentives on CRM units to trade in the ex-ante market (as the exposure associated with a trip is too extreme), crippling liquidity, or may result in the addition of significant risk premiums to cover the risk of the potential double exposure created by participation in ex-ante markets. Either out-turn would increase cost for suppliers, and therefore the consumer.

The issue of scarcity pricing therefore needs careful consideration in the context of the wider energy market and must consider imbalance pricing arrangements and likely liquidity levels in the forward contract, day-ahead and intra-day markets. We believe referencing ROs to any other market than the day-ahead market could cause significant liquidity issues in both ex-ante spot and forward contract markets (this is discussed in more detail in our answer to the question below). Energia has also previously identified two potential sources of liquidity issues in the intra-day market, ESB market power and the TSO approach to system dispatch (see our responses to the Market Power Workstream Discussion Paper and our response to the ETA Markets Consultation Paper), and we request that these are also careful considered in the debate on scarcity pricing. We also request that the efficacy of the hedge provided to suppliers by ROs is also considered in the debate if ROs are, in some form, referenced to the balancing market (e.g. the level of the strike price and its effect on suppliers and generator incentives). The lower the strike price the higher the risk of participation in ex-ante timeframes for generators (including the forward contract market) and the less the incentives on suppliers to self-balance. The higher the strike price the less effectual the hedge provided by the RO to suppliers and the greater their potential exposure, given the possible liquidity issues in ex-ante timeframes referenced above.

Energia cautions that these are extremely complex, difficult issues, with serious consequences for participants and I-SEM consumers. They therefore require substantial further careful analysis and consideration. We find it unhelpful that the discussion of such issue has been parachuted into the CRM workstream and has not, to date, been properly debated as part of the energy trading arrangements, and we therefore recommend that scarcity pricing, moving forward, is primarily dealt with under the ETA workstream. Furthermore, there is the risk that the current approach to debating scarcity pricing may not promote proper consideration of its implications on wider energy market dynamics, including participant risk management, as there is currently an unwarranted assumption that ROs can provide suppliers with a sufficient hedge against scarcity pricing (which is subject to the level of the RO strike price, the reference market and the implications decisions on these have for trading incentives under the energy market arrangements). Energia therefore has concerns that potentially important issues, such as those set out above, may not be properly considered.

**C) The choice of market reference price options from amongst the options presented and consistency with key objectives.**

The only viable reference price for reliability options within the context of the I-SEM market design is the day-ahead market, assuming appropriate exemptions from / limits on obligations under RO pay outs (e.g. to eliminate scheduling risk, to accommodate participation of wind generation, etc). We discuss the rationale for this, and the potential issues with the other reference markets further below. Please note we do not consider scarcity pricing options explicitly in this assessment. Our views in relation to scarcity pricing have been clearly presented in our answer to the previous question.

**The Balancing Market**

Referencing ROs to the balancing market will cripple liquidity in ex-ante markets as participants will simply not take on the basis risk associated with trading in ex-ante timeframes. Referencing ROs to the balancing market will therefore undermine liquidity in the ex-ante spot markets and consequently the efficiency of market coupling (the primary rationale behind introduction of the I-SEM market changes in the first place). Unless the RAs are prepared to allow the forward contracts market to migrate to the balancing timeframe, referencing ROs to the balancing market would also consequently undermine the I-SEM forward contracts market, which is already a problematic area for the I-SEM, presenting a risk to retail competition. Therefore, these two outcomes seem contrary to the stated intentions of the SEM Committee and the objectives of the Forwards and Liquidity workstream.

The proposed solution to liquidity in the day-ahead market, mandated submission of offers combined with voluntary submission of “virtual bids”, does not remove the basis risk. While it provides a trading mechanism to manage the risk, the difficulty of accurately forecasting scarcity in the balancing market in practice will mean significant basis risk remains for sellers of ROs and / or CfDs. This is because one of the primary drivers of scarcity in real time, forced outages, is inherently unpredictable. Another complication, due to the high level of wind penetration in the I-SEM, is the potential for significant changes in wind generation levels to trigger scarcity events (e.g. due to the technical constraints on generators ability to respond). Subject to exemptions for dispatch risk, such commercial risks will therefore need to be priced into the price of the option and, in this instance (and others), care would need to be taken that the design of the RO scheme itself does not result in the imposition of unnecessary commercial risks on participants, and therefore unjustifiable costs on the consumer; at a high level that the benefits of the RO hedge outweigh the costs of its implementation. This is a difficult dynamic under a centralised scheme as risk on sellers of ROs increases as the strike price decreases, while the efficacy of the hedge for buyers of ROs decreases as the strike price increases and any necessary exemptions / limits on exposures are added.

Further potential issues with the “virtual bids” mechanism include:

- The ability for CRM units to manipulate a market reference price (assuming CfDs remain referenced to the DAM) by clearing their own offers (which is effectively manipulation of market demand).
- If CRM units are mandated to participate in the day-ahead market it increases commercial risks under forward contracting even with a “virtual bidding” type trading mechanism (again assuming CfDs remain referenced to the day-ahead market). This is because if a CRM unit forecasts scarcity in the balancing market and submits a virtual bid, but that scarcity event does not occur, the day-ahead market price may out-turn higher than the balancing market price creating an exposure (basis risk) for the generator under its CfD. This is an example of how the basis risk does not disappear under a “virtual bidding” type trading mechanism. Our concern is this residual risk would undermine the proper functioning of the I-SEM forward contract market.

Leaving to one side the issues discussed above, the primary mechanism that drives supply and demand equilibrium remains the balancing market price. Imposition of ROs does not change this fundamental dynamic but it does change the balance of commercial risks associated with the cost of imbalances between the supply and demand side, subject to the level of the RO strike price and the value placed upon scarcity in the balancing market arrangements. In effect ROs struck on the balancing market price transfers this commercial risk from the demand side of the market onto the supply side (from suppliers to generators) by capping exposures on the demand side and doubling up exposures on the supply side (at least for generators who choose to contract through ex-ante markets). Under such an arrangement, a supplier, if short, is subject to the balancing market price capped at the RO strike price, whereas a CRM unit, with a day-ahead or intra-day market position, if it trips, is subject to the uncapped balancing market price, plus a difference payment, if the balancing market price is greater than the RO strike price. This in turn creates trading incentives whereby demand (suppliers) are less incentivised to balance and supply (generators) are less likely to take on ex-ante contract positions. In the context of the objectives of the I-SEM energy market design (including balance responsibility, efficient ex-ante market coupling and in the absence of self-scheduling) such incentives do not seem overly helpful.

In light of the issues highlighted above the balancing market is therefore not a viable reference market for ROs. Nor will referencing ROs to the balancing market necessarily increase incentives on CRM units to supply energy at times of system stress (relative to the incentive created by the balancing market price itself). This is because CRM units will presumably adjust their trading behaviours to minimise their exposure under their RO contracts (i.e. will withdraw from trading in ex-ante timeframes) to avoid any potential double exposure.

**The Intra-Day Market**

The continuous nature of the intra-day market means it is not a suitable reference market for ROs as not all supply and demand will be subject to the same price. This creates commercial risks for CRM units if some form of averaging methodology (creation of a market index price) is adopted, as they may have traded but not achieved this price. A similar issue arises with a combination of intra-day auctions and continuous trading, as a generator can only trade their output once. Depending on their choice of how and when they trade a generator could therefore be subject to RO pay outs without securing the revenue stream required from the market. These problems are particularly acute if there is the risk of low liquidity in the intra-day market.

In light of the issues highlighted above the intra-day market is therefore not a viable reference market for ROs.

**Multiple Reference Price Options**

***Option 4a***

In relation to option 4a it is difficult to understand how the payments will balance assuming a firm cap on prices on the demand side (for suppliers) under the RO scheme. This is because despite any individual market price going above the RO strike price, a generator may not be subject to difference payments if their volume weighted average trade price, achieved across all markets, was less than the RO strike price. To maintain the hedge for the demand side (suppliers) under such an approach would therefore require some form of slush fund subsidised by the consumer – i.e. it creates another 'hole in the hedge'. The alternative, removing the blanket hedge for the demand side (suppliers), undermines the benefits of the hedge provided to suppliers under the RO. In relation to the forward contract market it is also difficult to see how this approach could be made to work as there is no market wide price at which difference payments under forward energy contracts (normal 2 way CfDs) could be dis-applied. Adopting such an approach for RO referencing pricing would therefore undermine conditions for liquidity in the I-SEM forward contract market, which we have previously highlighted is a significant risk to retail competition[10]. A further concern is the unintended trading incentives such an approach could generate. These are discussed in section 2.6 and appendix C of the NERA report accompanying this submission.

In light of the issues highlighted above Option 4a is therefore not a viable approach to determining a reference price for ROs.

***Option 4b***

While option 4b is designed to mitigate basis risk, we have concerns regarding its complexity and the practical issues that may therefore arise with implementing it within the challenging timelines of the I-SEM project plan. We observe that implementing option 4b would effectively require designing three products, one for each reference market. Furthermore, we note the lengthy timelines associated with the ongoing implementation of the Italian RO scheme which operates upon a similar model[11]. We also have concerns regarding the potential complexity of pricing an RO under this approach, given the uncertainty introduced by multiple reference markets.

We further observe that while option 4b may facilitate participation in the day-ahead market, it does not actually incentivise such participation, as implied in the consultation paper. Consequently, in the absence of mandated participation in the day-ahead market for CRM units, the complexity of the arrangement (including the difficulty of pricing the option across a number of possible markets) may result in trading activities naturally migrating to a single market to reduce the overall complexity of participants contracting and risk management activities. If this migration in trading activities is towards the

[10] See Energia's response to the Forwards and Liquidity Discussion Paper SEM-15-028.
[11] Because of its complications, the first delivery year was postponed from 2017 to 2020, and a preliminary simplified auction intended to minimise the impact of these delays is also behind schedule.

balancing market then this would result in the same issues as discussed in relation to referencing ROs to the balancing market. Option 4b is therefore not guaranteed to be a better option than Options 1a or 1b, despite its significant additional complexity, and may still have the overall effect of drawing liquidity out of ex-ante markets. On the other hand, if day-ahead market participation is mandated for CRM units, or trading naturally migrates towards the day-ahead market, then it is unclear why the complexity of implementing option 4b is required, as a similar result could have been achieved much more easily by referencing ROs to the day-ahead market.

In relation to the incentive to make generation available to the balancing market we would again emphasise that under any reference market for ROs (even the balancing market) it is not the RO contract that delivers this incentive, but the cost, including lost opportunity, of the CRM unit relative to the balancing market price. We would also note that under grid code, generation units are obliged to make their units available and that the I-SEM balancing market is mandatory. We therefore see no additional benefit to availability offered by ROs under Option 4b relative to any other reference market option. As NERA observe[12]:

*"The short term incentive to provide capacity depends on the value of the BM in both normal conditions and periods of system stress, even if generators possess CFDs and ROs …."*

Furthermore, given the overall complexity of Option 4b it is difficult to accurately assess what its potential effect on trading incentives may be, or whether the complexity of its implementation is likely to be offset by any actual accrued benefits. As discussed above it is not even clear whether it offsets the downside of referencing ROs to the balancing market (i.e. the removal of liquidity from ex-ante timeframes). We therefore consider that taking the decision to implement Option 4b would be a high risk approach under the current project timelines, based on evidence of the Italian implementation process, and observe that it could potentially result in unanticipated and unwelcome outcomes for the TSO, participants and consumers under the wider I-SEM market design, this is without any clearly identified benefits compared to the simpler option of referencing ROs to the day-ahead market.

In light of the issues highlighted above Option 4b is therefore not a viable approach to determining a reference price for ROs.

**The Day-Ahead Market**

As discussed above, if it is the balancing market price, rather than the RO contract or its reference price, that primarily incentivises generators to deliver

[12] NERA, 14 August 2015, 'The Capacity Remuneration Mechanism in the I-SEM – Detailed Design', page 17.

energy, then referencing ROs to the day-ahead market will not undermine the incentives on generators to provide energy during system stress events. Making the incorrect assumption that it would weaken incentives to generate is therefore not a valid reason to discount this option. Furthermore, referencing ROs to the day-ahead market supports liquidity across ex-ante timeframes, and will therefore help promote efficient ex-ante market coupling. It will also promote liquidity in forward contract markets by removing basis risk (subject to the recommendations made earlier in this section in relation to setting the RO strike price, minimising impacts on the forward contract market and the change to load following arrangements discussed further in our answer to the next question). It also helps maintain incentives on the demand side (for suppliers) to self-balance (i.e. does not hedge balancing market prices) and is the only option that is guaranteed to be consistent with the approach to scheduling adopted under the I-SEM market design (which relies upon liquid ex-ante trading, assuming the final design precludes the self-scheduling of generation).

However, implementing the required measures to make the RO work within the context of the wider energy market (i.e. adopting a high strike price and referencing the day-ahead market) significantly undermines the utility of implementing an RO type scheme in the first place. This is because the impacts of real time scarcity will be muted in the day-ahead market (e.g. the effect of forced outages cannot be anticipated, nor extreme changes in the output of wind generation) and therefore ROs are extremely unlikely to be called undermining the efficacy of the hedge. It therefore raises fundamental questions as to why an RO scheme is appropriate for I-SEM, given the tight project timelines and the implementation risk it presents given the complexity of the interactions of RO contracts with the energy trading arrangements. Energia observe that this implementation risk would be significantly reduced if a 'GB style' mechanism were adopted.

A further major drawback of an RO type scheme in the context of the I-SEM is the fact that, regardless of the deemed eligibility status of wind generation, the complexity of the mechanism, and the commercial risks it imposes, mean that, in practice, wind is unlikely to accept / secure a contract unless the strike price is set extremely high and wind generation is exempted from RO pay outs, or at least its downside exposure is capped at a low level. The latter options effectively add to the 'hole in the hedge' issue given the projected levels of wind penetration in the I-SEM. To effectively exclude wind from the mechanism however (by not providing relief from the commercial risks) would seem contrary to wider environmental policy objectives in relation to renewables targets, given the negative effect it would have on existing projects and securing financing for future wind generation projects.

**D) Whether the RO volume and/or the additional performance incentives should be load-following.**

Energia supports the principle of the load following approach but observe that as the strike price of the reliability option reduces the risk of the option being called when some RO contracted generation is not scheduled / dispatched increases. Even under the load following approach suggested in the paper this could result in generators having financial exposure under ROs, as although the obligation of each generator has been reduced in proportion to demand, less efficient units may not have been scheduled when the RO is called, and therefore are exposed to the difference payment across their adjusted RO contract volume. This commercial risk would have to be reflected in the capacity price to ensure the full recovery of "missing money" and would therefore increase costs to consumers. We request that this issue is carefully considered in the design of load following obligations. We believe setting a high strike price, such that ROs are only likely to be called when all demand is scheduled, may help to mitigate this problem but recommend that ROs are scaled back on an ex-post basis relative to the generators actually scheduled in the RO reference market when the RO was called. Note we would obviously not support the obligation being scaled back for generators who were unavailable due to forced outage.

The inclusion of operating reserve in the calculation of the scaling factor should be reviewed as it could increase commercial risk on generators if the reference price for ROs is the balancing market price (note we do not consider the balancing market as a viable reference price as discussed in our answer to the question above). This is because generation is not physically scheduled to demand plus reserve margin levels. Therefore adding operating reserve to demand in the calculation of the scaling factor may result in the total RO contract volume not being adequately reduced to ensure that scheduled RO generation meets demand. This is less of an issue if ROs are referenced to an ex-ante market price as generators presumably will not have their output reduced to provide operating reserves until after intra-day market gate closure.

Energia sees the 'hole in the hedge' caused by de-rating, ineligibility and out of contract generation as a major drawback to the implementation of ROs. To maintain a 100% hedge level on the demand side (suppliers) consumers will have to fund the shortfall in payments between revenues collected from RO contracted generation and difference payments made to suppliers. This effectively removes the cap on consumer prices provided by ROs, undermining one of the original perceived benefits of the mechanism. In the case of wind generation the cost of funding this shortfall (the 'hole in the hedge' caused by non-participating wind) is additive to the cost of the REFIT support mechanism, either on its output above its de-rated level, or its total output (i.e. if wind is ineligible or incentive penalties on intermittent generation are overly punitive, effectively excluding wind generation from the RO mechanism). This is because the PSO required, at least in the case of REFIT, is not being offset by any capacity receipt received by the wind generator. It also generates a cash flow issue for the administrating party of the RO scheme.

**E) The requirement for, and design of additional performance incentives, including:**

Given the balancing market price is the main incentive to provide energy at times of system stress discussion of penalties should be conducted with reference to the likely incentives provided by the balancing market, and in particular the approach to imbalance pricing. To the extent that the balancing market is sufficient to incentivise delivery of capacity at times of system stress, the need for additional performance incentives is reduced. The appropriateness of delivering incentives to generate via the balancing market however, rather than through the imposition of performance incentives linked to the CRM scheme, depends on the wider energy market dynamics, and, in particular, the ability of participants (especially suppliers) to manage their exposure to volatile balancing market prices. Therefore the debate on performance incentives is directly linked to the debate on imbalance pricing, which in turn, is linked to the debate on the likely dynamics of the wider energy market design (e.g. liquidity levels in ex-ante timeframes including the forward contract market).

Furthermore, as a general principle, and while acknowledging the likely need for performance incentives under the CRM scheme, Energia would emphasise that it is important the I-SEM does not impose unmanageable commercial risks on participants, otherwise there is an increased risk of market failure. Therefore, given the complexity of this area, and its significance for the success of the I-SEM, we recommend that a working group is set up to determine an appropriate performance incentive regime under the CRM scheme, within the context of the wider I-SEM energy market design.

***a. The form of additional incentives;***

Energia observe that performance incentives should work at the margin to ensure that the penalty / reward for under / over provision of capacity is greater than the incremental cost of providing that capacity. Furthermore there may be benefit in considering an approach whereby revenues from CRM units that under deliver on obligations is re-distributed to those that over deliver under the CRM scheme. This would provide both a ‘carrot’ and a ‘stick’ in relation to CRM unit performance but may present risks to competition, given the extent of ESB dominance in the capacity market. This is discussed in more detail in our answer to the next question.

Energia would stress that the design of an incentive mechanism requires careful consideration and further detailed debate with stakeholders to ensure the incentives introduced under the CRM scheme are appropriate, in the sense of not exacerbating market power concerns, and not unduly penalising participants who cannot modify their behaviours, which would simply impose unmanageable commercial risks on some eligible CRM participants. It is therefore important that exemptions rules are considered (e.g. for intermittent generation, or generation subject to scheduling / dispatch risk, etc.), as well as the need for caps and floors. We discuss both of these in more detail in our answer to later questions.

Designing appropriate incentives is extremely complex and therefore requires further careful consideration and debate with stakeholders via the working group proposed for this area.

***b. Scarcity based triggers for performance incentives***

Energia sees merit in using a definition of scarcity as a trigger for performance incentives but would observe that careful consideration needs to be given to the treatment of CRM units on planned generation outages (i.e. outages pre-agreed with the TSO). It would seem somewhat incongruous to penalise generators on planned outage (an operation required to maintain good availability standards) under a performance incentive regime. It is also important to consider market power dynamics, given the dominance of ESB within the capacity market. In particular the potential to withdraw capacity to create scarcity events to foreclose on competition (e.g. if a competitor, or competitors were on a forced outage) or profit maximise on other parts of their extensive generation portfolio. Strict monitoring would need to be put in place to mitigate this market power concern, which could be exacerbated depending on the design of the performance incentive regime (e.g. if revenues from under-performing CRM units were transferred to CRM units that over-perform the portfolio benefit to ESB could be substantially greater than the cost incurred on any withheld capacity). It is also possible that ESB, as a state owned company, could trigger such events, even at cost, to foreclose on competition. This market power concern requires very careful consideration and Energia recommend that close monitoring of ESB behaviours is required if a performance incentive regime is introduced.

***c. Caps and floors on incentives;***

The introduction of caps and floors within a performance incentive scheme would seem sensible and may help to some extent reduce market power concerns. We would emphasise, however, that such an approach would not be sufficient to mitigate them. Furthermore, not introducing a limit to a participant's exposure under a performance incentive regime is likely to deter investment, undermining the primary purpose of the CRM scheme, while the level that limit is set at will determine the additional risk premium (and therefore cost) levied on the consumer. There is also a balance to be struck between capping downside risk and exemption from penalties.

Again this is an extremely complex area and requires further careful consideration and debate with stakeholders via the working group proposed for this topic.

***d. Performance incentives for renewables and DSUs;***

Energia requests that careful consideration is given to ensuring that the CRM design is consistent with the current policy objectives relating to renewables and demand side participation.

Intermittent wind generation, assuming they are eligible to participate under the scheme, require exemption from performance incentives or substantial capping of downside commercial risk, otherwise their eligibility would be undermined because of the commercial risk associated with their participation. Excluding wind, either through ineligibility or imposition of penalties, would have serious consequences for investment in the sector and therefore achievement of renewable targets.

In the case of DSUs we believe careful consideration needs to be given to any performance incentives to ensure they do not, in themselves, become a barrier to demand side participation. However it would be unwise for the scheme to pay for demand side units that, in reality, did not contribute to system security during stress events.

***e. Performance incentives during the pre-commissioning phase;***

Whilst there may be reasons to implement performance incentives during the pre-commissioning phase careful consideration needs to be given to the design of any such incentives to make sure they do not, in themselves, become a barrier to entry, undermining future investment in the market. In particular, it is an important principle that the design of any such incentives should not impose penalties on investors in new capacity for outcomes that are demonstrably outside of their control.

Noting the complexity associated with taking investment decisions Energia therefore recommends that there is further debate with stakeholders on this topic to help ensure proper consideration of all of the issues, given the importance of generating the market conditions required to deliver new investment into the I-SEM in the future. This could be accommodated via the working group proposed for this area.

***f. Detail of any other considerations respondents feel that we should take account of when determining policy in relation to product design***

**Interactions of ROs with I-SEM Forward Contract Market**

Careful consideration needs to be given to the interactions between ROs and the I-SEM forward contract market, which under an RO scheme is still required for participants to fully manage their exposure to commodity price risk. Given the liquidity issues already prevalent in the SEM forward contract market, it is essential that the design of reliability options does not interfere with, or destabilise, the normal operation of the I-SEM forward contract market, undermining participants ability to secure an effective hedge, or increase commercial risk premiums on forward contract pricing, which would result in a direct increase in costs to consumers. The recommendations we have made in this section should help reduce these risks but may not eliminate them.

Furthermore Energia maintains that the implementation of ROs reinforces the requirement for an exchange based approach to forward contract trading under I-SEM. Such an approach would facilitate the central development of a standard CfD contract via the Forwards and Liquidity workstream (bilateral negotiation of contract terms can be onerous and extremely time consuming) to try to minimise any potential and unnecessary contractual barriers to liquidity in the forward contract market generated due to the implementation of an RO scheme. The implications of grandfathering and multi-year ROs also need to be carefully considered as discussed in our answer to the question on that topic above.

**Exemptions under ROs and Performance Incentives for Scheduling / Dispatch Risk**

Even if, as we have recommended, a high strike price is adopted for ROs, potential issues relating to scheduling risk (if the reference market is the day-ahead market) and dispatch risk (which occurs if ROs are referenced to the balancing market and technical constraints prevent a generator from being dispatched by the TSO when the BM price exceeds the RO strike price) nevertheless remain. Energia requests that the extent of scheduling risk in the day-ahead market is assessed as part of the EUPHEMIA trial. To minimise such risks Energia proposes that generators that have submitted a "valid offer" to the referenced energy market (e.g. are physically available and have offered below the RO strike price) 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. Similar provisions should be made for generators who are scheduled / dispatched but ramping up to meet demand in such periods.

As a more general comment, Energia caution that extreme care needs to be taken in this area to ensure that the design of ROs and / or any performance incentive regime does not impose unnecessary commercial risks on participants – i.e. risks that are not reasonable for the participant to manage, or that are simply outside of their control. Imposition of such risk will not have a positive effect on behaviour but will increase the cost of the scheme for the consumer, may deter investors and therefore undermine the efficacy of the scheme as a capacity mechanism. On the other hand, care also needs to be taken that exemptions / caps on penalties do not create unintended trading incentives for participants. This is therefore an extremely complex and difficult area that requires substantial further debate and consideration via a working group, as proposed in our answers to previous questions.

## *Chapter 4: Eligibility*

**A) The options presented in relation to the eligibility of plant supported through other mechanisms;**

In principle all plant that is capable of contributing capacity to the system should be considered eligible to participate in the capacity mechanism, including renewables.

As IWEA have stated in their response, if REFIT supported generation was unable to participate in the CRM, the result would be a significant increase to the PSO and it is unlikely that the consumer will see any benefit from this change.

For NIRO supported generation, it should be noted that many projects invested on the basis of receiving capacity payments, and if supported generation was not to be eligible, this would have a significant impact on the investment case for these projects. The impact of wind energy reducing the wholesale price of electricity, which is a significant benefit to the consumer, and the removal of LECs in the UK, should also be taken into account when considering the impact of the CRM on the investment case for these projects.

Furthermore, if the SEM Committee were to exclude these generators from the CRM, their combined capacity credit would be netted off the contracted volume, indicating that they provide a capacity credit - this should be remunerated like all other capacity. In particular with renewables becoming an increasing part of the market, it is essential that the capacity mechanism is consistent with the change in generation portfolio and steps should be taken to facilitate this as proposed by IWEA.

The consultation paper refers to longer term ancillary service contracts and notes the importance of not overcompensating recipients of such contracts through the CRM. It is not entirely clear what this refers to as DS3 system service products (as currently defined) do not reward the provision of capacity and are not paid on the basis of availability. As mentioned earlier in this response, careful consideration should be given to the treatment of capacity providers with long term capacity contracts that are outside the CRM (both in terms of eligibility to participate in the auction and the capacity requirement adjustment) to ensure the market is not distorted by such interventions – this does not seem to have been considered in the consultation paper. For example as Poyry point out in their report, when SONI awarded a three year capacity contract to AES in 2014 to help meet an anticipated shortfall in capacity in Northern Ireland in the coming years no attempt was made to isolate the effects of this intervention on the energy or capacity market.

As a final point, it is worth noting that the continued subsidisation of Peat in Ireland is anomalous. On this note we have previously responded to the Building Blocks consultation as follows stating that removal of priority dispatch status for peat should be a priority for the SEM Committee moving into I-SEM in the overriding interest of the electricity consumer, security of supply and the environment. It is anomalous to support peat-fired generation through the PSO on a security of supply basis, and to afford peat-fired generation priority dispatch in the market. If peat, as an indigenous fuel, is to provide a security of supply benefit in the long term, it should be preserved – i.e. Ireland should not be consuming it as quickly as possible and at a time when there is an abundance of alternative, albeit imported, fossil fuels that would be less costly to the electricity customer and (in the case of gas) less carbon intensive. In addition, it is grossly inconsistent for policy and market treatment to support and prioritise the generation of electricity from a carbon intensive fossil fuel such as peat given the ongoing transition to a low carbon economy.

**B) The options for eligibility of demand side and storage providers**

Consistent with the principle espoused above, all plant that is capable of contributing capacity to the system should be considered eligible to participate in the capacity mechanism and this should include demand side participation and storage.

However any special treatment of demand side needs to be designed to avoid the cost of double counting or overcompensating demand side response. As NERA point out in their report[13]:

*"Achieving this outcome requires (1) that the baseline methodology is robust as objective as possible (i.e. difficult to game) and (2) that the baseline level of demand before DSR, rather than the actual level of demand after any reduction, enters into the formula used to define the total capacity requirement".*

Option 2 as proposed in section 4.7 of the consultation paper would appear to overcompensate demand side response is certain circumstances.

With respect to energy storage, it is not clear what is being proposed. The consultation paper states that the RAs will work with the system operator to define minimum requirements that energy limited plant must meet, and how their de-rating factor is determined. Given its effect on the market it is

[13] NERA, 14 August 2015, 'The Capacity Remuneration Mechanism in the I-SEM – Detailed Design', page 21.

imperative that the methodology is determined in a transparent and consultative manner.

**C) Do you have a view on the technology vs plant specific approaches to derating?**

Adopting a centralised generic approach to de-rating by technology type (market segment) is likely to mute incentives on individual CRM participants to outperform their allocated benchmark, thereby creating a systemic inefficiency in the capacity market. There are inherent difficulties in setting an appropriate benchmark for each market segments. If the benchmark is set on average historic performance, and historic performance has been poor, it may 'lock in' that trend of underperformance. If it is set too high (based on aspiration) it may result in under procurement of capacity and increase costs for consumers, due to higher energy market prices and / or through the addition of risk premiums to the CRM price. If the benchmark is set too low it results in the over procurement of capacity, again increasing costs for consumers. Energia therefore recommend centrally determined, plant specific de-rating factors. Subject to the mechanism used to calculate de-rating factors (discussed further in our answer to the question below), such an approach maintains incentives on each individual plant to improve their availability over time, allowing the capacity market, relative to the value of "missing money" in the energy market, to incentivise a more efficient outcome for consumers.

Energia would also note that there may be reasonably large discrepancies in the performance of individual units within each market segment and therefore, to the extent there is "missing money" in the energy market, it would seem inequitable on CRM participants not to recognise these performance differences via plant specific de-rating factors.

**D) Do you have a view on the historic, projection or hybrid approaches to derating?**

Energia would recommend setting plant specific de-rating factors objectively by means of a formula based upon historic performance. Care would need to be taken in relation to how this formula is defined, to ensure it appropriately identifies the longer term trend in each CRM unit's availability, and to avoid excessive year on year volatility in de-rating. Consideration would also need to be given regarding how standard planned maintenance cycles were taken into account by the formula. For example, the minor / major outage cycles of CCGTs should not unduly affect year on year de-rating factors.

Energia acknowledges that, in some instances, such as new build, historic data is not available, or, in the case of significant investment in upgrades, may not be representative. Therefore, in practice, a hybrid approach is likely to be required. In the case of new investment, generic, factual data, based on the performance of that technology in other markets, should be used. In the case of refurbishment or upgrades, participants should be required to provide strong factual evidence to support any requested adjustment to their historic trends. The process for implementing changes to historically derived de-rating factors should be clearly defined and defined as part of the design process. Furthermore it should be made subject to robust governance and appropriate oversight to safeguard the integrity of the CRM scheme is maintained.

Energia requests that the option to implement a generator testing regime under the CRM is consulted upon. Such a regime would have to ensure full recovery by the generator of the full costs imposed by testing, and any interaction with TSO incentives around dispatch balancing costs would need to be considered to ensure incentive compatibility. The purpose of the regime would be to eliminate 'ghost' capacity from the CRM, capacity that has a high availability simply because it is never called to perform, but if required (i.e. during a system stress event) may be unable to deliver. Consideration should also be given to how reliability could be equitably factored into the de-rating methodology and, if testing is adopted, how best to take into account the results in the de-rating formula.

If a centralised plant specific approach is adopted, given the link between de-rating and performance incentives, we would suggest that this area is further considered and debated by the workstream on enforcement and the worksteam on capacity definitions proposed above.

**E) Do you have a view on grandfathering of de-rating factors?**

To reduce perception of regulatory risk, and to provide the conditions required to support investment, Energia recommend that grandfathering is employed in relation to de-rating factors. Implementation of grandfathering however could take the form of the right to maintain a fixed de-rating factor (capacity contract level) over an agreed duration of time, subject to performance.

To promote the efficiency of the CRM scheme a mechanism may be required that increases the de-rating (capacity contract level) of long term capacity holders. For convention capacity this could be an automatic adjustment as per the methodology set out in our answer to the previous question, while for intermittent generation it may make more sense if the decision to reduce their long term capacity contract level is made on a voluntary basis (i.e. made by the participant).

To maintain incentives to improve availability, at least in the case of conventional CRM units with grandfathered de-rating factors (i.e. non-intermittent generation), de-rating could also be allowed to reduce over time, increasing contracted capacity levels, if such units improve their availability. This again could be achieved via the methodology set out in our answer to the question above.

The suggested approach to grandfathering would provide certainty for investors, while maintaining incentives on holders of long term capacity contracts to improve availability. It also provides a mechanism whereby the capacity market can readjust for under performance against benchmarks for long-term capacity contract holders.

**F) Do you have a view on options presented with respect to the non-firm generation?**

Energia recommends that conventional non-firm generation is eligible to participate in the capacity market, at its own risk, with a de-rating factor based upon a projection of the unit's likely transmission system access during system stress events (i.e. Option 2 as presented in the consultation paper). We would emphasise that to maintain the intent behind the concept of firm access it is important that conventional, non-firm generation is not exempted from pay outs under ROs, or performance penalties, if unable to access the transmission system during system stress events. To avoid barriers to new entry, Energia would however advocate that generators whose firm access has been delayed, due to factors beyond their control, should be granted "deemed firm access".

As a general comment Energia would stress that the implementation of the current firm access policy under the I-SEM energy and capacity trading arrangements requires further urgent clarification. In particular, how the current firm access policy, including compensation for transmission constraints, will be implemented in the I-SEM balancing market for participants that do not hold ex-ante contract positions.

**G) What evidence should an aggregator be required to show physical backing?**

Aggregators should have to prove they have physical backing but the burden of proof should not be unnecessarily onerous or duplicative (e.g. it could be linked to renewable support accreditation where possible).

**H) 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?**

There should be no restriction on the size of intermittent renewable generators that can be included in an aggregated portfolio. However targeted market power mitigation measures should extend to dominant entities providing or using aggregation services.

**I) Should there be a minimum size below which a capacity provider may not bid directly into the RO auction, and must bid via an aggregator? If so what is that threshold?**

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 unless combined with other capacity through an aggregation service. The threshold should be no greater than the GB threshold of 2MW.

**J) What pre-qualification criteria should be applied?**

Pre-qualification rules and criteria need to be carefully thought through in conjunction with industry and rules should be more specifically tailored than suggested in the consultation paper which only distinguishes between (1) existing plant and (2) new / refurbishing plant. For example, particular consideration should be given to pre-qualification requirements for demand side participation to ensure the demand side capability can be proven and is not over-stated.

For new / refurbishing plant strict pre-qualification requirements should be specified and robustly enforced to ensure the physical capacity is delivered on time but some consideration should also be given to potential delays that are unambiguously beyond the developers' control.

**K) Detail of any other considerations respondents feel that we should take account of when determining policy in relation to eligibility.**

Mandatory participation in the RO would appear problematic on a number of counts.

As IWEA have elucidated in their response from a wind perspective, the RO presents risk to market participants which may be difficult to assess adequately in advance of historical data on the market outcomes resulting from a new market design. Whilst advocating mechanisms to reduce or mitigate this risk, IWEA is of the view that participation should be optional because some variable generators may consider the option of earning scarcity rents through the energy market more prudent than trying to manage the risk of participating in the RO.

Of course the risk of participation applies more broadly than wind and it may be the case that some generators might choose to apply for a lower de-rating than their historical performance would imply (commensurate with their risks of participation) but this would appear to conflict with mandatory participation.

Furthermore if additional penalties are included in the RO design, then it would appear to presuppose a discretionary requirement, allowing parties to evaluate the implications of such penalties in their decisions.

## *Chapter 5: Supplier Arrangements*

**A) Whether the recovery of CRM option fees from Suppliers should be on a flat, profiled, or focused basis.**

In relation to option fees it is difficult to understand how profiling of payments could be introduced, in the absence of similar profiling on generator receipts, without opening up a large imbalance of payments, and therefore a substantial cash-flow issue for the administrator of the scheme. Any balance of payment issue would need to be funded and therefore raises the overall cost of the scheme to the consumer.

The introduction of sculpting of payments / receipts in relation to the option fee however undermines the benefit of introducing an RO based CRM scheme in the first place (i.e. the hedge of volatility in the energy market price). The extent of this issue depends upon the methodology used to profile capacity receipts / payments and the value set for the RO strike price. The lower the RO strike price, the higher the value of the option, and the greater the payments from suppliers to generators via the capacity market (as opposed to the energy market). The more sensitive the profiling mechanism, the better the signal to demand, but the more volatility removed from the energy market is reintroduced via the capacity market. A similar argument holds for the focused basis (i.e. GB type approach).

On the other hand, not to sculpt the supplier payments would further undermine the demand side signal under an RO scheme. This dampening of the signal would be particularly acute if ROs were referenced to the balancing market, and therefore capped demand side exposure to the balancing market price.

Energia cannot identify a particularly attractive solution to these issues but considers, on balance, that minimal profiling in conjunction with a high strike price, or a flat charge to suppliers, at least for the option fee component of the capacity charge, is the only approach that seems consistent with the intent of the RO (i.e. to provide a "hedge" to volatility for generators and suppliers). Note that the issue of provision of demand side signals is not as problematic an issue under a 'GB style' mechanism as, in the absence of the reliability option component, a 'GB style' scheme would not need to maintain the semblance of a 'hedge' on either the generation or demand side. If the RO however does not provide an effective 'hedge' it is difficult to understand the purpose of introducing the complexity of a reliability option scheme into the I-SEM market design, particularly in the context of the challenging implementation timelines.

Given that there is no optimal solution to this issue, and in conjunction with the other issues discussed in this response (i.e. the 'hole in the hedge', the uncertain impacts of ROs on energy market dynamics, the risks implementing ROs pose to the I-SEM forward contract market, etc.) it fundamentally questions the basis for choosing ROs.

**B) Whether the Supplier credit cover arrangements for the I-SEM CRM should be broadly similar to those under the SEM, and whether / what credit cover arrangement should be introduced for capacity providers.**

Energia would emphasise the need for a properly collateralised I-SEM energy and capacity market but request that the overall credit requirements placed on participants are optimised to ensure sufficient collateralisation is achieved with minimum overhead. Such an approach will ease the credit burden for existing participants, ensure excessive credit requirements do not become a barrier to new entry, and lower costs for consumers.

Energia have set out a number of suggestions on how this could be achieved below:

- Adopt a 'GB style' capacity mechanism rather than ROs. ROs are effectively a financial energy contract and a CRM mechanism (assuming there is a performance incentive regime, which seems likely from experience in other markets). Therefore they increase the credit requirement on participants relative to a more straightforward capacity market design.
- If ROs are implemented then Energia observe that increasing their strike price will reduce the credit cover required. We therefore recommend a high strike price set as a % of VOLL (e.g. 50% of VOLL subject to the value set for VOLL). Note if scarcity pricing is introduced this may not sufficiently reduce credit requirements.
- Facilitate the netting of a CRM unit's potential exposure to difference payments against their capacity receipts to reduce their credit requirement.
- Facilitate the netting of credit between companies that operate both a generation and supply businesses up to the minimum of its supply or generation position. This would significantly reduce credit requirements for such companies without imposing financial risks on the wider market. In the case of the capacity market the generation business would then forgo its capacity payment up to the value of capacity payments made by the supply business, if the supply business defaulted, and the supply business would forgo difference payments under ROs up to the value of the difference payments due from its generation business, if the generation business defaulted. We note this does not reduce the credit burden for merchant generation, and therefore may not alleviate any potential barriers to entry created by the implementation of an RO scheme.
- Profiling of charges to suppliers and payments to generators should be matched to maximise the opportunities for netting. Subject to the discussion in our answer to the question above, we believe in relation to the RO part of the scheme, which is supposed to provide a "hedge" to volatility in the energy price for generators and suppliers, this is best achieved either by not profiling option fees (so these can directly net

for companies with generation and supply positions) or by imposing only minimal profiling on the supply side (so netting can be maximised).

Energia observe that careful consideration needs to be given to whether the increased collateralisation required by an RO scheme is warranted compared to a ‘GB style’ mechanism, which would be significantly less credit intensive because of the absence of an energy contract component.

More generally, Energia note the likely need to set a high strike price for ROs, explained in our answers to previous questions (which may not sufficiently reduce credit requirements if scarcity pricing is introduced), in conjunction with the potential, and unnecessary, difficulties ROs create for the forward contract market, undermine the efficacy of ROs as a risk management instrument. Furthermore, the complexity of RO schemes, caused by their direct interaction with the energy market, including their potential effects on trading incentives, poses significant risk of unanticipated and potentially costly, unintended consequences for consumers, particularly given the reasonably short time available for their implementation under the challenging I-SEM project. It is therefore not clear why they have been chosen as the I-SEM capacity mechanism.

**C) Whether the costs of exchange rate variations (arising from differences in the €/£ exchange rate at the time capacity is procured and its subsequent delivery) should be borne by capacity providers or mutualised across the market.**

The costs of exchange rate variations should be mutualised across the market.

## *Chapter 6: Institutional Framework*

**A) Are the above outlined governance arrangements suitable for implementation of the I-SEM capacity mechanism?**

Energia supports the proposal that the market operator should carry out settlement of CRM.

The Capacity Mechanism Delivery role should be a TSO function, but only providing that potential conflicts arising from EirGrid‟s ownership of EWIC are eliminated or robustly managed (as discussed in our response to the I-SEM Roles and Responsibilities consultation SEM-15-016), and irrespective of this, that the delivery body role does not extend to the design of the capacity mechanism (or its subsequent modification). The consultation paper states that TSOs should be the delivery body for the I-SEM Capacity Mechanism because this is in line with their statutory duties regarding security of supply. We do not consider this stated rationale relevant or appropriate to the question of who should be delivery body for two reasons. First, the design of the capacity mechanism does not appear (and should not be) within the scope of the delivery body role. And second, long term security of supply is not the primary responsibility of the system operator from a generation adequacy perspective. Primary responsibility rests with the regulatory authorities, acting on behalf of consumers. Discussion of the system operator's obligations to ensure a safe and secure power system should not therefore be confused with obligations to maintain long term generation adequacy which is the function of a capacity mechanism.

**B) Which options for contractual arrangements are the most appropriate as assessed against the listed criteria?**

The Energia preference is for the "Rules Based Model", subject to robust and transparent governance arrangements.

**C) Are implementation agreements required for new entrants participating in the capacity auctions?**

Implementation agreements are required for new entrants participating in the capacity auctions to ensure that a contractual commitment is in place to deliver the physical capacity promised. These agreements should be strictly enforced to ensure that physical capacity is delivered according to programme, but some consideration should also be given to potential delays that are unambiguously beyond the developers' control.

# Annex 1 – Referenced Reports

- NERA Report, August 2015, 'The Capacity Remuneration Mechanism in the I-SEM – Detailed Design'.
- Poyry Report, June 2015, 'Review of Consultation on Proposed Annual Capacity Payment Sum for 2016'.

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# The Capacity Remuneration Mechanism in the I-SEM – Detailed Design

## Prepared for Viridian

14 August 2015

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# Contents

# 1. Introduction

On 2 July 2015 the SEM Committee released a consultation (the “SEM Consultation”) on the Detailed Design of the Capacity Remuneration Mechanism in the Integrated SEM (I-SEM).[1] The SEM Consultation provided a detailed outline of the Regulatory Authorities’ perspective on the full range of design issues.

## 1.1. Our Instructions

Viridian has asked us to focus on three topics when addressing the RAs’ proposed detailed design of the capacity market mechanism. These three topics are:

- setting strike prices and the Market Reference Price;
- capacity obligations; and
- penalties and enforcement.

We have addressed these topics by:

- reviewing the proposed arrangements for the design of these key elements of the scheme;
- providing input on the economic rationale behind the scheme design; and
- highlighting any trade-offs between objectives, to inform finalisation of the design.

We conclude with some suggestions for organising the next stage of design work on the CRM.

## 1.2. Summary of Findings

The RAs have chosen Reliability Options (ROs) as the high-level design for the capacity mechanism in the I-SEM. Holders of ROs will have to pay the difference between the market reference price and the strike price to the system operator whenever the market reference price rises above the strike price. In the next stage of design work on the capacity market, the RAs will select the strike price and reference prices for the RO contracts.

In this consultation, the RAs are soliciting advice on several features of the ROs. We have considered a number of aspects of RO design and our conclusions are as follows.

- **Level of strike price (chapter 2)**

The risks surrounding the selection of the RO strike price are asymmetric. In principle, a range of different strike prices would offer some additional incentive to provide capacity. However, practical considerations point towards setting a strike price towards the higher end of the feasible range. The lower the strike price, the more often holders of ROs will pay money to the system operator, the more valuable ROs will be, and the greater the proportion

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[1] I-SEM – Capacity Remuneration Mechanism Detailed Design (2015), Consultation Paper, SEM Committee, SEM 15-044, 5 July 2015.

of market participants' revenues will pass through the capacity market, rather than the energy market. Many aspects of the method used to recycle revenues from holders of capacity to supply businesses create unhedgeable risks for participants, and ultimately costs for consumers, with no offsetting benefit in additional security of supply. All other things being equal, the lower the strike price, the larger the volume of capacity holders' remuneration flowing through the capacity market, and the larger the unnecessary risks and costs that will ultimately be borne by consumers. ISO-NE is proposing to eliminate the Peak Energy Rent adjustment from its CRM, due to its poor performance as a hedge for Loads and the fact that hedging can be provided adequately by other means. This change would eliminate the problem for generators identified here.

- **Choice of Market Reference Price (chapter 2)**

The Market Reference Price (MRP) used to settle ROs must be taken from a "reference market". The choice of this reference market does not materially affect the incentives for delivery of energy (or capacity) during scarcity events: irrespective of the Market Reference Price chosen, and regardless how many ROs or Contracts for Difference (CFDs) each market participant holds, the incentive (i.e. the additional revenue) for providing additional output in real time is the Balancing Market price. However, the selection of Market Reference Price will drive trading and contracting behaviour. Traders will seek to minimise their exposure to basis risk and therefore have an incentive to trade physical output at the MRP and to sign CFDs settled against the MRP, which has important implications for competition and liquidity.

Market participants will shift trade into the relevant reference market as a way to eliminate basis risk. If I-SEM rules direct market participants to trade in markets other than the reference market, they will need to find (and be allowed to adopt) methods to mitigate that risk. For instance, the use of "virtual bids" would allow market participants to pass electricity right through the directed market and into the reference market; however, this solution may give rise to other potential problems, such as creating opportunities for manipulating market prices.

Taking the MRP from the Balancing Market would align all prices and risks, but would cause trade to focus on the BM and to shift away from the Day-Ahead Market. That might harm the liquidity of cross-border market coupling. Forcing market participants to trade in the DAM would create basis risk unless either the MRP was taken from the DAM or the MRP was taken from the BM and market participants could use virtual bids to transfer electricity from the DAM to the BM. The Intra-Day Market will not be liquid enough to provide a relevant MRP. Mixed schemes for defining the MRP bring additional complexity into the settlement of ROs and CFDs. As such, they increase the difficulty of hedging whilst offering little if any reduction in the exposure to basis risk.

- **Regulatory objectives, as applied to CRM design principles (chapter 3)**

The principles of adaptability and stability promote economic efficiency by reducing uncertainty for market participants. Market participants are able to make more efficient decisions when they can predict future the market outcomes and the future of the market mechanism itself. The CRM will achieve more efficient outcomes if the RAs develop formulae or conceptual frameworks to reduce scope for regulatory discretion and provide greater certainty to market participants.

For example, to maximise transparency and efficiency, the RAs should specify formulae that define how the capacity requirement is calculated and how de-rating factors for new and existing plants will be measured; as far as possible, these formulae should use observable public data (i.e. historical data, not someone's forecasts). For the sake of adaptability and stability, such rules should as far as possible be unrelated to specific technologies (which may change in future), but should use instead plant-specific data.

- **Rewards, penalties and efficient risk mitigation (chapter 4)**

Rewards and penalties based on performance during times of system stress are the fundamental drivers than ensure the CRM solves the "missing money" problem. RO settlement gives capacity providers no additional incentive other than the market price, so they may lack the incentive to provide sufficient capacity. In such circumstances, CRMs must be bolstered by additional penalties and rewards for providing more or less physical capacity during periods of system stress.

These rewards and penalties need to be targeted to encourage efficient decisions without creating unnecessary risks. The availability of any capacity may be affected by both internal and external factors – i.e. factors that are within the control of the plant operators (like maintenance) and factors that are outside their control (like the level of wind). When availability depends on external factors, then imposing penalties on capacity providers offers no additional incentive, whilst the additional risk of penalties outside their control discourages capacity providers from building capacity and participating in the scheme.

For instance, many CRM schemes put a cap on total penalties over short periods, to limit their financial impact on capacity providers. Such caps mitigate the risk of bankruptcy, particularly for unmanageable external risks that market participants cannot unwind through offsetting hedges. By doing so, they help to encourage participation in the CRM and hence to produce a more efficient outcome overall.

Thus, where it is impossible to distinguish clearly between the effects internal and external factors on output, the most *efficient* schemes offer a trade-off between incentives and risk mitigation (even if incentives are *muted* as a result).

- **Next steps**

The design of the CRM would benefit from industry input:

- on the implications of particular strike prices and MRPs for risk and liquidity, organised as a **workstream on pricing**;
- on the technical and plant-level data to be used in CRM formulae, organised as a **workstream on capacity definitions**; and
- on the economic and financial parameters used to define and limit rewards and penalties for providing capacity, organised as a **workstream on enforcement**.

## 1.3. The Structure of this Report

This report proceeds as follows:

- Chapter 2 assesses the potential methods of determining the strike price for a Reliability Obligation contract and of setting the Market Reference Price;
- Chapter 3 discusses how to define capacity obligations, including the capacity requirement, de-rating factors and load following obligations.
- Chapter 4 discusses the economic principles behind enforcement and incentivising capacity provision through penalties.

The report also includes the following appendices:

- Appendix A provides a short case study of the Italian Capacity Market Mechanism with a focus on the approach to setting the Market Reference Price.
- Appendix B provides a short case study of the ISO New England Market with a focus on the pay-for-performance scheme (proposed in conjunction with the removal of the Peak Energy Rent adjustment) scheme and the treatment of intermittent generation.
- Appendix C is a technical appendix on the incentives created by the blended approach to setting the Market Reference Price.
- Appendix D provides a formal description of the financial flows under the RO and the implications of a scenario where trading and RO settlement occur in different markets.

# 2. Strike and Market Reference Prices

This chapter outlines the economic rationale behind various approaches to setting the strike price and the Market Reference Price (MRP) and highlights the key trade-offs between objectives inherent in the choice of approach.

The chapter first sets out considerations for setting the strike price. This is followed by a detailed outline of the appropriate criteria for setting a MRP. The last four sections assess options for the MRP against these criteria. The four options are:

- Balancing market;
- Intra-day market;
- Day-ahead market; and
- Mixed schemes.

## 2.1. Setting the Reliability Obligation Strike Price

The strike price sets the level at which the TSO can call the RO option. It acts as a cap on the revenue received from the spot market for capacity covered by an RO contract.

The mechanism by which the strike price is set determines when and how often the RO is called, and hence how the risk of entering into a RO contract is allocated and shared among market participants. Below, we explore the ways in which the strike price affects the risk of participating in the RO:

- the absolute level of strike price and the extent to which this reflects the costs of capacity from the marginal plant;
- the implications of setting multiple strike prices; and
- the method of adjusting the strike price over time to account for changes in the underlying costs of the marginal plant.

### 2.1.1. Setting the level of the strike price

In principle, the strike price of the ROs limits consumers' exposure to high energy prices, but the strike price is not only determined by consumers' dislike of occasional price spikes. An equally important objective for the ROs is to reduce the risk facing generators and to encourage more investment in capacity, compared with a market where incentives and rewards depend on peak energy prices alone.

If the strike price is set too high, for instance near to the Value Of Lost Load (VOLL), investors in capacity remain dependent on (and consumers remain exposed to) the risk of relatively high energy prices occurring from time to time. However, managing this risk is not an insurmountable task and can be dealt with through standard hedging approaches.

If the strike price is set too low, for instance equal to the marginal cost of an efficient mid-merit generator, consumers may feel protected against price spikes, but the scheme will fail to encourage investment in mid-merit or peaking generators – one of its main purposes – since the low strike price exposes them to “volume risk” or “scheduling risk”.

Scheduling risk is a particular form of volume risk facing capacity providers who have ROs (or CFDs) in place but whose generator plants that do not run all the time. It is the risk that the RO is called (and incurs difference payments) at times when the plant is not running (and so not earning any offsetting revenues). That situation arises when the MRP is (1) above the RO strike price but (2) below the marginal cost of generating electricity from these plants. The first condition arises often when the strike price is set at a low level. The second condition arises because some mid-merit and peaking generators have quite high marginal costs for running in short periods of system stress, given their start-up costs and ramping constraints. A low strike price therefore exposes some capacity providers to substantial (and unnecessary[2]) risk. We discuss of difficulties in hedging further in Section 2.2.1.

The consultation document recognises the need to set the strike price so that it reflects the short run costs of the highest cost (“marginal”) generator in the market. In Ireland this is expected to be peaking gas or oil-fired plant.

However, to avoid “scheduling risk”, the value used to set the strike price should include all the marginal costs of generating electricity, the not just the variable or “incremental” cost of generating at peak times, once the plant is running. For a peaking generator, the cost of reaching full output at times of system stress includes not just the incremental costs of generating, but also some additional costs, such as the cost of starting the plant. The additional cost may also include a running cost per hour and (if necessary) the cost of running the plant out-of-merit (i.e. at a loss) in the minutes before and after the period of system stress, when it is ramping up to and down from full output.

The SEM Consultation acknowledges but does not fully consider these inter-temporal issues.[3] However, it is not unusual for electricity markets to attribute the additional costs of generation to periods of peak demand, or system stress. For instance, the rules of the old Electricity Pool of England and Wales (1990-2001) incorporated these additional costs into the formula for the System Marginal Price. Other markets expect and allow generators to include these costs in their offer prices per MWh generated at such times. When defining a formula for the strike price, the formula will either have to incorporate the additional costs of peaking generation in the formula explicitly, rather than relying on generator’s including them in offer prices. Alternatively, the strike price could be set with reference to VOLL, which would eliminate the issues associated with incorporating the full costs of the marginal plant altogether.

2 ISO-NE is proposing to eliminate the Peak Energy Rent adjustment from its CRM, due to its poor performance as a hedge for Loads and the fact that hedging can be provided adequately by other means. This change would eliminate the problem for generators identified here.

3 See SEM Consultation Section 3.2.2 and footnote 20.

### 2.1.2. Single or multiple ("grandfathered") strike prices

The consultation document asks a question about the duration of the strike price – whether there should be a single strike price at any one time (updated as discussed below), or whether the reference unit for each strike price should be fixed ("grandfathered") at the time when the RO is issued, which would lead to multiple strike prices at the same time. (See paragraph 3.2.6 and question A)c. in paragraph 3.10.1.)

The consultation suggests that "grandfathering" the reference unit might be beneficial for investment in new capacity, but notes that the resulting multiplication of strike prices might make it difficult to manage the risk of a portfolio. In practice, the latter argument dominates the former. A vintaged strike price would tend to reduce liquidity in the CfDs and increase the cost of risk management. Market participants are less likely to invest if they are less able to manage their risks because the cost of risk management is high.

The purpose of ROs is to limit exposure to very high market prices, not to hedge specific generators. Investors in new capacity will not necessarily build plant with the same marginal costs or running regime as the reference unit. Thus, ROs will not provide investors in new capacity with their main tool for hedging market risk. Investors who want to share electricity market risks will still have to rely on the contracts they sign with buyers.

The parties to such contracts will have to adjust them so that they do not overlap with the ROs, which would otherwise undermine their function as a tool for risk management. (The adjustment will take the form of an exemption from difference payments when the MRP exceeds the RO strike price, or a call option that offsets the main contract in such conditions.) These adjustments should not, ideally, limit the tradeability of the associated contracts. If different vintages of RO have different strike prices, the resulting adjustments would be specific to certain generators. That would limit their value in trade and hamper contract market liquidity. Such contracts would not be attractive to new investors.

Overall, therefore, we conclude that investors in new capacity would not benefit from having some tailor-made RO with a vintaged strike price that would upset their role as a tool for risk management. Instead, investors are likely to favour ROs and contracts that follow a standard design with a common strike price at any one time.

### 2.1.3. Updating the strike price over time

The method by which the strike price is updated over time to reflect changing market conditions is another important determinant of the risks associated with the level of strike price and the overall efficiency of the mechanism.

If the strike price is tied to level of VOLL then updating the strike price is simply a matter of adjusting for inflation. However, if the strike price is tied to the costs of the marginal generator, the process of updating is inherently more unpredictable.

Above, we discussed how to avoid "scheduling risk" by basing the strike price on the marginal costs of the highest cost ("peaking") generator, including incremental cost of generating and the additional costs of reaching full output. The formula for defining the strike price at any time needs to preserve this condition, at the very least by reflecting changes in the price of fuel for the reference unit, and if necessary by switching to a more expensive reference unit when there is a change in available technologies or in relative generation costs.

The precise details of this updating will be relatively simple and are not important to investors, provided that the method of updating the strike price is (1) stable, (2) public and (3) clearly defined. Investors and market participants will then be able to manage their risks effectively by allowing for the effects of this method (or by referring directly to this method) in the adjustments to their contracts mentioned above.

## 2.2. Setting a Market Reference Price

The SEM Consultation provides a set of criteria for assessing various options for the Marginal Reference Price (MRP)[4]. For the purposes of this discussion, we have combined these criteria into more concise objectives. In summary, the choice of the market reference price aims to achieve three main objectives:

- to facilitate risk management for market participants;
- to provide incentives to provide capacity when there is a shortage; and
- to encourage competition and liquidity in the wholesale markets.

The remainder of this section discusses these three objectives in detail. We cover the RA's first criteria on security of supply and incentives for capacity provision in the discussion of our second objective. We cover the RA's second, fourth and fifth criteria on EU internal market integration, liquidity and market power, respectively, in the discussion of our third objective. And finally, we cover the RA's third criteria, on efficiency and risk management in the discussion of our first objective.

### 2.2.1. The market reference price should facilitate risk management

A capacity mechanism introduces an additional set of financial flows between market participants. These flows are inherently uncertain and are therefore a potential source of additional risk for market participants, unless their variation offsets variation in other flows. The effect of the ROs must therefore be evaluated against the background of other financial flows, from markets and contracts.

When choosing a reference price the primary source of new risk is the basis risk caused by trading in a different market from the one used to settle the Reliability Options. The primary method of hedging the new risks created by ROs is likely to be a shift in trading into the market from which the MRP is taken. In principle, other approaches exist to manage these risks through alterations to CFD contracts, for example by including explicit adjustments for any differences in price between markets with the contracts. However in practice, such adjustments may not arise because:

- the quantity traded under the CFD is set in advance, whilst the quantities sold in the DAM and BM vary at short notice, so the CFD may not cover the actual quantity exposed to the

[4] See SEM Consultation, Section 3.5

price differential – unless the relative quantities are tied to a particular generator, making the CFD difficult to trade;

- the Balancing Market price may not even be identical to the balancing price received by an individual generator, if ever a pay-as-bid pricing rule applies (either in general or, e.g., for generators behind a transmission constraint).
- traders may find it difficult to agree upon a common contractual form that achieves this adjustment
- volumes of CFDs and ROs may not match in total, so that generators and suppliers cannot actually achieve a risk-hedging combination of CFDs and ROs.

This "modified CFD" approach avoids the complexity of "blending" market reference prices, but only by forcing market participants into an equivalent "blending" of contract volumes. Consequently, this approach of adjusting the CFD contracts to account for price differentials between the trading and reference price, pushes the complexity to the generator and supplier for managing risks rather than adopting administrative procedures that help participants.

We are not aware of any cases where traders have adjusted their CFDs in the manner described here to cope with the overlap between the hedging properties of CFDs and ROs. We also note that ISO NE referred to persistent difficulties over risk management in its proposals to reform the capacity mechanism in New England. Therefore, whilst we recognise that there may exist solutions to the risk-hedging problems caused by ROs (especially those with low strike prices), we do not believe that these solutions can necessarily be implemented in contracting timescales. A more likely outcome is either a decline in liquidity, as different traders adopt different contractual solutions, or the persistence of the problem with risk hedging that harms investment incentives.

### 2.2.2. The market reference price does not provide short term incentives for generation or consumption

The reference price and the extent which it reflects market conditions influences the incentives for providing capacity.[5] To obtain a clear picture of how the MRP influences the incentives for providing capacity we consider the incentives facing a bidder in two cases when market prices are high (above the RO strike price):

1) when generator output is less than the de-rated capacity of the plant, i.e. less than the generator's contracted quantity of ROs; and
2) when generator output is greater than the de-rated capacity of the plant, i.e. more than the generator's contracted quantity of ROs.

In the first case, when output is less than the RO contract quantity, capacity providers face a choice between two outcomes. They can provide the capacity, receive the market revenue and then make a difference payment to the TSO out of revenues received from market prices above the RO strike price. Alternatively, they can fail to provide the capacity and still make the same difference payment to the TSO. The difference between these two scenarios lies

5 See SEM Consultation, Section 3.65

only in the revenues at market price and so the incentive to provide or withdraw any additional unit of capacity is the market price received for output from the marginal unit of capacity. Importantly, this market price need not be from same market that is used to set the MRP; generators are free to seek out the market with the highest price. It is only from a risk minimisation perspective that it is rational to offer capacity into the RO reference market.

In the second case, when the capacity provider is already providing sufficient capacity to meet the RO contract quantity then the capacity provider will simply receive its marginal revenue from the market in which the additional capacity is offered and accepted.

Hence, irrespective of the market where the MRP is set, the incentive to provide an additional unit of capacity comes from the achieved market price for the output of that unit. Therefore, incentives are only driven by market prices. The choice of MRP only affects operating decisions by influencing the requirements for risk management.

In a sense, therefore, the RAs can separate two decisions. They can set the formula for prices in the DAM and BM to reflect the expected (or current) degree of scarcity; this decision will determine the short run incentive to make capacity available. They can then select the reference market for the MRP in ROs as a contribution towards the long run incentive for building and maintaining capacity. As discussed below, the latter decision might take into account the need to focus trade in certain markets (as the by-product of efficient risk management) both to facilitate cross-border trade and to promote competition and liquidity within the I-SEM.

### 2.2.3. A market reference price should promote competition and liquidity

The choice of market reference price should be taken in the knowledge that it will determine the manner in which generators and suppliers wish to participate in each of the wholesale electricity markets. Active participation and liquidity in both the day-ahead and balancing markets is important for risk management and also, in a market with a single dominant firm, namely ESB, for restricting the potential exercise of market power. The remainder of this chapter therefore appraises three of the four options for the choice of MRP, set out in the SEM Consultation,[6] in terms of their consequences for liquidity and market power. These options are:

1. Balancing Market price;
2. Intra-Day Market price (which we do not consider in detail);
3. Day-ahead Market price; and
4. Mixed reference price schemes (as found, e.g., in Italy).

In the following section we discuss options for setting the reference price and how these perform against the criteria set out above. Note that we do not consider at length the possibility of using the Intra-day Market, due to the low liquidity and the difficulty of choosing a single reference price in a market with continuous trading.

[6] See SEM Consultation, Section 3.6

## 2.3. Option 1: Balancing Market for Reference Price

Option 1 in the SEM Consultation involves setting the MRP as 100% of the Balancing Market price – assuming that the Balancing Market is structured so that it produces an unequivocal price for each trading period. In our discussion of this Option, we consider the issue of administrative scarcity pricing, which is raised within the SEM Consultation[7].

### 2.3.1. Risk management and sharing

The use of the BM price as the MRP would create a new risk for market participants to manage. In many descriptions of the future system, it is assumed (for reasons that are not always clearly stated) that most output is sold in the DAM and that most contracts refer to the DAM or the DAM price in their settlement. In this case, referring to the BM price in ROs would create either a new basis risk, or an incentive to shift the trade in physical output and contracts from the DAM to the BM.

The BM price reflects actual conditions as they arise, whereas the DAM price reflects expected conditions and may not capture the effect of unexpected changes in demand, network conditions or generator availability. If contracts continued to be settled against the DAM price, whilst ROs were settled against the BM price, market participants would face basis risk due to the difference between the prices, and might find it difficult to adjust their contracts to avoid the overlap of hedging (see Appendix D). Any additional risk placed on capacity providers would be expected to increase their costs and hence prices to consumers. However, within the SEM and I-SEM, the ability to include these costs in offer prices may be constrained by regulation, so that capacity providers would have to include the costs of basis risk instead in their bids for ROs.

A more likely outcome is for market participants to change the way they trade, in order to eliminate the basis risk in the first place. If the BM allows them to sell their output at the MRP (i.e. if it sets a single price for every trading period), generators can avoid basis risk by selling their output in the BM and signing CFDs settled against the BM price up to the RO strike price This trading strategy might require a reform of system operation, since the TSO would no longer be able to count on the forecast of output and offer prices provided by the DAM. Forcing generators to make day-ahead offers would preserve the current status of the DAM, but would also impose basis risk on them.

### 2.3.2. Incentives for capacity provision

The BM is likely to be the most volatile and unpredictable of all electricity market prices, since it reflects all the unpredictable changes in system conditions. Generators, suppliers and customers would be insulated from the financial effects of that volatility by the hedging properties of CFDs and ROs, especially if they were settled against the BM price. The short term incentive to provide capacity depends on the value of the BM in both normal conditions and periods of system stress, even if generators possess CFDs and ROs, since any deviation in output above or below the volume of these contracts will attract the BM price. In the

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[7] See SEM Consultation, Section 3.4

medium-to-long term, the incentive to invest in building capacity and keeping it available depends on the revenue to be obtained from CFDs and ROs, which depends in turn on the expected future value of the BM price. The formula for the BM price therefore underpins all incentives for capacity provision.

The strength of this incentive depends on a number of factors, including:

- regulatory constraints on offers and bids submitted into the Balancing Market;
- whether administrative scarcity pricing is applied in the BM and, if it is:
  - how the administered value is set;
  - the conditions in which it is applied; and
  - the frequency with which those conditions are expected to arise (or their probability).

The answers to these questions will affect every one of the Options for the MRP. In general, the lower the BM price is expected to be in times of system stress (if the administered scarcity price is low or absent, or if scarcity is unlikely to occur), the lower the value that market participants will attribute to ROs and the more incentives will rely on additional penalties for not providing physical capacity. The ETA work stream will need to take into consideration the interaction between the BM price and the incentive to provide capacity and the hedging instruments required by suppliers.

### 2.3.3. Competition and liquidity

The RAs noted in the SEM Consultation[8] that setting Balancing Market price as the MRP may reduce liquidity in the Day-Ahead Market. Under the EU target model, market coupling is currently performed on a day-ahead basis, so reduced liquidity may interfere with an efficient market coupling process.

One proposed solution is to make it mandatory for bidders to offer the output from their capacity into the DAM (see Sections 3.5.1 and 3.6.5 of the SEM Consultation). However, making bidding compulsory in the DAM raises risks for capacity providers that have uncertainty around their future output at the day-ahead stage, e.g. intermittent generation, as they cannot adequately respond to changes in the technical characteristics of their own plant by bidding in the balancing market.

One way to support compulsory bidding in the DAM by maintaining flexibility for participants is the scheme known as “virtual bidding”. Virtual bidding allows market participants to take financial positions in the physical electricity markets,[9] i.e. to submit offers and bids unrelated to actual generation or consumption. It helps to promote price convergence between the two markets by allowing bidders to manage their positions in each market more freely and to arbitrage prices between markets. In this case, it would also help them manage basis risk, if ROs (and CFDs) were settled against the BM price. Generators would be obliged to *offer* their plant into the DAM, but would then be allowed to place a

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8 See SEM Consultation, Section 3.6.5

9 Celebi, M., Hajos, A., & Hanser, P. Q. (2010). Virtual bidding: the good, the bad and the ugly. The Electricity Journal, 23(5), 16-25.

virtual *bid* in the DAM to buy the same amounts at the same prices, so that in net terms they would close out their position in the DAM. That would then free them up to participate in the BM.

This scheme preserves the benefits of a liquid DAM whilst avoiding the need to impose basis risk on market participants who sign up for ROs settled against the BM price.

However, the implementation of virtual bidding may provide opportunities for capacity providers to manipulate their bids to alter the market reference price. This may be particularly important in the context of the Irish market given ESB's market position. The market power mitigation work stream should take account of the potential market power issues associated with virtual bidding.

## 2.4. Option 2: Intra-Day Market for Reference Price

Option 2 in the SEM Consultation would take the MRP from the Intra-Day Market (IDM). We do not consider this option in detail, as it seems to us to be impractical. The IDM consists either of a number of separate markets operating at defined intervals during the day, or as a continuous market in which trades can take place at any time. Neither of these possibilities would be capable of setting a useful reference price for settling CFDs or ROs.

## 2.5. Option 3: Day-Ahead Market for Reference Price

Option 3 in the SEM Consultation involves setting the market reference price as 100% of the day-ahead market price.

### 2.5.1. Risk management and sharing

If the MRP is set as the DAM price then both operation of the system by the TSO and risk management is likely to follow the general pattern that seemed to be envisaged in the I-SEM HLD.

To manage their risks efficiently, generators will want to sell their output in the DAM, and to sign CFDs referenced against the DAM price up to the RO strike price, at least to the same extent that they possess ROs. Only minor deviations would be bought or sold in the Intra-Day or Balancing Markets.

The incentive to participate in the DAM will also complement – and might even replace – any obligation on generators to offer their plant to the DAM. The TSO would therefore continue to receive day-ahead notice of availabilities and offer prices, for use in scheduling and despatching generator capacity.

This Option therefore promises a minimum (albeit some) amount of disruption to arrangements for trading and despatch that generally seem to be envisaged in the I-SEM HLD.

### 2.5.2. Incentives for capacity provision

The SEM consultation argues that the use of the DAM price as the MRP provides weak incentives to provide capacity, because the DAM price is less closely aligned with actual system conditions than the BM price[10]. At the time when the DAM clears, the price only reflects a best guess of what system conditions will be like at the time of actual dispatch. To the extent that system stress arises only when system conditions change between the clearing of the DAM and BM, the DAM price provides a muted or inaccurate incentive for the efficient provision of capacity.

However, as discussed above in Section 2.2.2, settlement of ROs does not in itself provide the incentive for efficient provision of capacity. ROs – or other forms of capacity mechanisms - give investors a more stable and predictable source of revenue for financing investment in capacity than relying on occasional spikes in the DAM or BM price at times of system stress. The purpose of the ROs is therefore to encourage investors to build more capacity and to invest more in keeping it available. Actual decisions to make capacity available at times of system stress, and to generate output from it, depend on the actual prices that arise in the DAM, IDM and, in particular, the BM. That is because the DAM price will determine a generator's reward for additional sales (or the cost of purchase) in the DAM relative to the volume of its ROs and CFDs, whilst the BM price defines the equivalent reward/cost for additional sales or purchases in the BM relative to the volume of sales in the DAM.

Thus, the incentive to respond efficiently to signals in the BM persists, even if ROs are settled against the DAM.

### 2.5.3. Competition and liquidity

Setting the DAM price as the MRP is likely to encourage generators and suppliers to trade through this market to minimise their risk. Under a RO scheme with the DAM as the MRP, exposure to the basis risk is minimised by trading equivalent volumes in DAM.

Setting the DAM as the MRP is therefore likely to increase participation and liquidity in the DAM. That outcome would contribute towards the efficiency of day-ahead market coupling within the EU target model.

This increased participation in the DAM may reduce participation and liquidity in the Balancing Market, unless, as we understand will be the case in I-SEM, the market rules also ensure participants make capacity available in the balancing market. At times of system stress, lack of liquidity in the BM could create circumstances where dominant firms emerge and can exercise market power to raise or lower BM prices (whichever suits their contract position). The extent to which such outcomes can be prevented by regulatory oversight is not yet clear.

[10] See SEM Consultation, Section 3.6.2

## 2.6. Option 4: Mixed Schemes

A mixed scheme involves setting a reference price based on some combination of market prices. This section considers the two approaches outlined in the SEM Consultation, namely:

- a blended scheme (Option 4a); and
- a split scheme (Option 4b)

Under both these approaches, the Market Reference Price for ROs is set by taking a weighted average of the prices in the DAM and BM. The SEM Consultation does not state explicitly how these schemes would reconcile sales of capacity in each market with the volume of ROs. However, the two most likely schemes seem to correspond to the "blended" and "split" schemes, as we show below for the case where.

- capacity providers have ROs for 8,000 MW and;
- they sell 7,000 MW in the DAM and 2,000 MW in the BM.

The price could be an average of DAM and BM prices weighted in the proportion 7,000:2,000, or the formula could take only the volume of BM trades needed to match the RO volume, i.e. use weighting of 7,000:1,000.

The term "blending" seems to apply best to the weights derived from actual sales (7,000:2,000). Below, we examine the incentive properties of such a rule, i.e. setting the proportions based on total sales in each market – in this case, weighting the DAM and BM prices respectively by 7/9 and 2/9.

Under a split approach, ROs are cleared against the DAM price for the volume offered into and accepted in the DAM. A volume of ROs equal to the capacity accepted in the BM, up to the remaining RO contract volume, is cleared against the BM price. In the above example this would equate to 7,000 MW being cleared against the DAM price and 1,000 MW being cleared against the BM price, or a weighting of 7,000:1,000. That approach would allow market participants to hedge by matching their CFD volumes to their sales volumes and offsetting the RO volume (see **Box 1** in Appendix D). The other 1,000 MW of sales in the BM would be unhedged and would act as an accurate, short term incentive for providing capacity. (The split scheme could also make the adjustment to DAM volumes, i.e. use weighting of 6,000:2,000, but the rationale for using such a method seems weak.)

A split scheme of this type is currently proposed for the Italian capacity market which is intended to come into operation through auctions for capacity contracts in late 2015. See Appendix A for a case study on the Italian scheme.

### 2.6.1. Risk management and sharing

Mixed schemes are intended to help capacity providers to manage the risks associated with offering capacity into multiple markets, by setting the applicable MRP based on actual bidding behaviour. For the sector as a whole, the basis risk associated with being dispatched at a market price that is different from the MRP is reduced by giving that sale a weight in the formula for the MRP. However, in practice, the scheme would seem to work only for the sector as a whole, and to leave individual generators exposed to basis risk of a particularly complex and unpredictable type.

For instance, in the example above, any small generator that sells 70 MW in the DAM and 20 MW in the BM would receive the hedging benefits (if any) of both the blended and split schemes. However, if the same generator sold 80 MW in the DAM and 10 MW in the BM, it would face basis risk on the 10 MW by which its own sales were misaligned with the sales of the sector as a whole.

Most generators would in practice sell different proportions of their output in the DAM and BM. Defining a different MRP for each capacity provider, using their own proportions of sales in each market, would create another problem for hedging, since each holder of ROs would want a different kind of adjustment to their CFDs to avoid the hedging. The result would be a disparate and illiquid market for CFDs.

Thus, neither the blended scheme nor the split scheme seem to offer the purported benefits for risk management – unless, for some reason, market participants proved unable to hedge the risks inherent in Options 1 and 3 using the methods set out above.

### 2.6.2. Incentives for capacity provision

In the previous Options, the marginal incentive to provide additional capacity at short notice remains the BM price, if the volume of ROs (and CFDs) is fixed. Adjusting the MRP for ROs in the light of actual sales to each market would affect that incentive, at least to some extent for large companies.

When deciding how much capacity to sell in the BM, a generator knows that it will be rewarded at the BM price. The ability to manipulate this price would distort incentives, as in any market, but mixed schemes create an additional dimension for market manipulation. Large generators will also know that a decision to provide additional capacity to the BM will affect the weighted MRP used for settlement of its ROs. That effect might conceivably either dampen or exaggerate the incentive to provide capacity.

For example, if the BM price is greater than the DAM, every additional unit of capacity accepted in the BM raises the Market Reference Price and the payment per MW to the TSO, due to the increase in the weighted average price. In this case, the weighting approach in the scheme dampens the incentive to provide capacity, as the capacity provider will not receive the full BM price. See Appendix C for a formal derivation of this result.

### 2.6.3. Competition and liquidity

The primary driver behind the adoption of a scheme that incorporates both the DAM and BM prices is the intention of minimising distortions to the level of participation in the two markets (DAM and BM). These mixed approaches would be attractive from the perspective of integration with EU market coupling, if they facilitate or encourage continued participation in the DAM.

However, the complexity inherent in these schemes may have the unintended consequence of discouraging participation in particular markets, as capacity providers look for ways to improve their risk management and approach to bidding. For example, the complexity associated with managing risks in CFDs under a complex MRP rule may encourage capacity providers to concentrate on participating only in the BM, to reduce the complexity of their contract and risk management strategy.

In addition, schemes with a high degree of complexity may favour larger firms relative to smaller firms, as larger firms will typically be better equipped to deal with complexity and to exploit potential opportunities.

## 2.7. Conclusions

The RAs have chosen Reliability Options (ROs) as the high-level design for the capacity mechanism in the I-SEM. Holders of ROs will have to pay the difference between the market reference price and the strike price to the system operator whenever the market reference price rises above the strike price. In the next stage of design work on the capacity market, the RAs will select the strike price and reference prices for the RO contracts.

- **The level of the strike price**

The risks surrounding the selection of the RO strike price are asymmetric. In principle, a range of different strike prices would offer some additional incentive to provide capacity. However, practical considerations point towards setting a strike price towards the higher end of the feasible range. The lower the strike price, the more often holders of ROs will pay money to the system operator, the more valuable ROs will be, and the greater the proportion of market participants' revenues will pass through the capacity market, rather than the energy market. Many aspects of the method used to recycle revenues from holders of capacity to supply businesses create unhedgeable risks for participants, and ultimately costs for consumers, with no offsetting benefit in additional security of supply. All other things being equal, the lower the strike price, the larger the volume of capacity holders' remuneration flowing through the capacity market, and the larger the unnecessary risks and costs that will ultimately be borne by consumers. ISO-NE is proposing to eliminate the Peak Energy Rent adjustment from its CRM, due to its poor performance as a hedge for Loads and the fact that hedging can be provided adequately by other means. This change would eliminate the problem for generators identified here.

- **Choice of Market Reference Price**

The Market Reference Price (MRP) used to settle ROs must be taken from a "reference market". The choice of this reference market does not materially affect the incentives for delivery of energy (or capacity) during scarcity events: irrespective of the Market Reference Price chosen, and regardless how many ROs or Contracts for Difference (CFDs) each market participant holds, the incentive (i.e. the additional revenue) for providing additional output in real time is the Balancing Market price. However, the selection of Market Reference Price will drive trading and contracting behaviour. Traders will seek to minimise their exposure to basis risk and therefore have an incentive to trade physical output at the MRP and to sign CFDs settled against the MRP, which has important implications for competition and liquidity.

Market participants will shift trade into the relevant reference market as a way to eliminate basis risk. If I-SEM rules direct market participants to trade in markets other than the reference market, they will need to find (and be allowed to adopt) methods to mitigate that risk. For instance, the use of "virtual bids" would allow market participants to pass electricity right through the directed market and into the reference market; however, this solution may give rise to other potential problems, such as creating opportunities for manipulating market prices.

Taking the MRP from the Balancing Market would align all prices and risks, but would cause trade to focus on the BM and to shift away from the Day-Ahead Market. That might harm the liquidity of cross-border market coupling. Forcing market participants to trade in the DAM would create basis risk unless *either* the MRP was taken from the DAM *or* the MRP was taken from the BM and market participants could use virtual bids to transfer electricity from the DAM to the BM. The Intra-Day Market will not be liquid enough to provide a relevant MRP. Mixed schemes for defining the MRP bring additional complexity into the settlement of ROs and CFDs. As such, they increase the difficulty of hedging whilst offering little if any reduction in the exposure to basis risk.

The design of the CRM would benefit from industry input on the implications of particular strike prices and MRPs for risk and liquidity, organised as a workstream on pricing.

# 3. Capacity Requirements and Obligations

This chapter reviews possible methods for setting the capacity requirement and the corresponding obligations on individual plants, in terms of (1) the quantity of capacity provided and (2) load following obligations.

In discussing these rules, we have adopted the position that, in order to be "stable", rules must be "adaptive". By this, we mean that the rules must be flexible enough to accommodate changing circumstances and should not require further regulatory intervention (and use of discretion) to adapt to developments in the market, such as the adoption of new technologies. In practice, this means avoiding rules that are specific to individual technologies ("wind", "solar") or which apply subjective concepts and measurements ("intermittency") but should instead refer to observable operating parameters (such as whether or not they are "despatchable", i.e. subject to central despatch).

To maximise "transparency", and hence "economic efficiency", we assume that the capacity requirement must be defined by a mechanistic formula that uses publicly available data on objectively defined variables. Such an approach allows market participants to make informed decisions about how the capacity requirement will be set in the future and allows market participants to produce their own assessments of demand in future auctions for capacity rights.

Our discussion of capacity obligations therefore focuses largely on how to foster economic efficiency by creating a transparent, but adaptive, measure of capacity requirements and obligations.

We note in passing that the SEM Consultation contains no discussion of the process for trading or transferring obligations between capacity providers. This appears to be a major omission which will need to be addressed in the near future. Given conditions in the market for ROs, with one central buyer, we do not envisage a liquid market in ROs emerging any time soon. However, capacity providers will undoubtedly want to be able to transfer ROs to others, if the availability of their plants changes unexpectedly. For the sake of transparency and efficiency, the process for registering such transfers of obligations needs to be defined from the outset.

## 3.1. Defining Capacity and Setting the Capacity Requirement

A stable, transparent and adaptive methodology must be able to deal with different technical capabilities, both now and in the future. Given the uncertainty surrounding the future characteristics and prevalence of individual technologies, it is difficult to base a stable scheme on technology-specific rules. Instead, to give market participants a long term view of the capacity market, it needs to develop a conceptual approach to assessing the capacity contribution of each potential source.

For example, consider the capacity contribution of wind capacity. In many markets, it is set as a rather low percentage of nameplate capacity, because the expected output of wind farms is rather low during periods of system stress, not least because such periods may be *caused* by a drop in output from wind farms. Given their special situation, some schemes adopt specific rules for wind farms, such as excluding them from capacity schemes altogether.

However, in the future, if the cost of electricity storage falls, developers might start to combine wind farms with storage facilities and then to claim that they are able to provide guaranteed capacity at times of system stress. Rules defined for wind technologies would then be outdated and inadequate. A new rule for the technology of "wind+storage" would be required. This rule would have to measure capacity contribution of such plant, taking into account the fixed capacity of the storage in MW, but also its limited volume in MWh, the possibility that the storage might not be completely full when the system came under stress, and the degree of control over its output granted to the TSO (its "despatchability").

"Adaptive" rules would accommodate these factors by focusing on the likely ability of the plant to provide energy at times of system stress, based where possible on actual experience, rather than on the supposed characteristics of a particular technology.

We note the question raised in paragraph 2.1.2 of the SEM Consultation as to whether the security standard should be changed. We cannot see why the introduction of a new scheme would require a change to the security standard, which depends on other factors. In economic terms, the security standard should seek on average to achieve a cost of outages (Value of Lost Load times Hours of Lost Load per annum) that is equal to the annualised cost of peaking capacity. Only changes in these parameters would merit a change in the security standard. The design of a CRM should merely reflect the current security standard (and render any other incentives for capacity redundant).

## 3.2. De-Rating Factors

The contribution of capacity towards total security of supply will vary between different technologies and, within a technology, between different plants or sources. Typically, the de-rating factor applied to nameplate capacity is a factor based on the forced outage rate ascribed to the plant, e.g.:

*Capacity Provided = Nameplate Capacity * (1 – Forced Outage Rate).*

To maintain an efficient balance of supply and demand, this formula needs to measure each source's expected contribution to supply at times of system stress. It also needs to maintain the incentive to make capacity available efficiently. This section outlines the key decisions around the definition of forced outage rates and de-rating factors.

### 3.2.1. Plant-specific versus technology-specific factors

De-rating factors can be defined for individual plants or as averages for all the plants using a distinct technology.

The discussion above highlighted the difficulty with referring to individual technologies in the rules on measuring capacity. A plant-specific approach is also likely to create stronger incentives for efficient management of capacity.

If individual plants are rewarded for their capacity using an average technology-specific factor, they will have little incentive to invest in raising their own capacity above this level (or in preventing it from falling below it). Only in certain special circumstances would it be necessary to adopt a more broadly defined measure:

- When a plant first comes into operation and has no established history from which its performance can be measured; and
- Generators with strong interdependence of availability, such as a common fuel source with limited deliverability, might potentially be accorded an aggregate measure of capacity, as a more accurate reflection of their actual contribution to potential supplies at times of system stress.

### 3.2.2. Historical versus forecast performance

A historical approach to setting the de-rating factor uses that actual observed performance of the plant to set its de-rating factor. A forecast approach involves assessing the technical characteristics of the capacity provider and using benchmarks of performance from similar plants to produce a forecast of its likely performance.

A historical approach fits the need for use of objective and publicly available data. However, the time period of the data used to set a historical rate needs to be sufficiently long to eliminate the potential for gaming the process. If the time period is too short, a generator may be able to game the process by focussing its effort on generating during the period when historical performance is assessed, rather than the period when its output or capacity is most valuable to consumers. Using data from a longer time period and providing incentives to exceed historical performance (and/or the current volume of ROs) can help to neutralise the temptation to game the process in this way.

A forecast approach might conceivably be more accurate, if capacity contributions have to be defined for auctions so far in the future that recent experience is a poor guide to likely performance. However, using forecast data can mean using subjective data, undermining the transparency of the scheme and the efficiency of decisions based upon it. It would only be advisable to use such forecasts when there are strong reasons to believe the future performance will differ significantly from historical performance, and there is a sound basis for measuring the trend in performance in objective and publicly available data. In any other cases, the benefit of using forecast data for accuracy is unlikely to outweigh the cost to transparency.

### 3.2.3. Non-firm access and de-rating

The treatment of plants without firm access raised questions around the allocation of risk within the system and the interaction of the capacity market incentives with transmission infrastructure. In order to reflect their capacity contribution accurately, de-rating factors applied to generators should capture their likely contribution to supply at times of system stress and hence should be adjusted to reflect the likelihood of the generator not gaining network access at such times. Generators with non-firm access need to be subject to penalties for failure to provide the de-rated capacity, subject to the provisions for exemption for failures caused by external factors (e.g. decisions by the TSO to withdraw network capacity from generators who have paid for a deep connection).

We note in passing that, at many times of system stress, output from wind farms and/or solar plants will be depressed. In such cases, there may well be enough network capacity to accommodate generators who lack firm access. The impact of non-firm access should therefore be assessed by taking account of the degree of coincidence between times of system stress and denial of access.

### 3.2.4. DSR and baseline

Any special treatment of Demand-Side Response (DSR) raises a concern over double remuneration of the supposed response – once through the saving in energy charges due to the reduction in consumption, and once through the payment for units of DSR actually provided. There is no comparable problem with double-counting of generation, because all energy production is accounted for in a market, whereas the payment for units of DSR may not be. The efficient solution lies in adopting a similar approach to settling the "baseline" for DSR, as we explain below.

Most DSR schemes ask the consumer (or its representative) to declare both their actual (i.e. metered) consumption and how much they have reduced it below their desired level of consumption (i.e. their DSR). The latter item is unobservable and highly subjective – even the level of consumption just before DSR is invoked may be a misleading measure of what the consumer would have consumed at time of system stress and very high prices.

A better approach (comparable with that adopted for generators) is to ask the consumer to commit to the desired level of consumption by signing a contract and showing that it has committed to pay for a certain volume of electricity in the period concerned. The consumer (and no other market participant) can offer to sell some or all of this volume back into the Balancing Market, as DSR. This approach effectively puts an efficient market price on the "declaration" of the desired level of consumption. It is rare for DSR schemes to apply this economically efficient approach to measuring the baseline.

Any alternative scheme needs to be designed to avoid or to minimise the cost of double counting DSR. Achieving this outcome requires (1) that the baseline methodology is robust as objective as possible (i.e. difficult to game) and (2) that the baseline level of demand *before* DSR, rather than the actual level of demand *after* any reduction, enters into the formula used to define the total capacity requirement.

## 3.3. Load Following Obligations

For the sake of efficiency, the rules for defining the load following obligation of each source of capacity must allow their providers to manage their risks. One risk facing capacity providers is the risk that they are not (or cannot be) despatched to run during a short period of system stress and high market prices, because their plant would take too long to start up, or is temporarily unavailable. A load following obligation helps to mitigate the risk to a capacity provider of not being dispatched during a period of capacity scarcity by reducing the obligation on the holder of any ROs to provide capacity in proportion to the level of demand and hence the relative scarcity of supply.

The SEM consultation outlines a proposed methodology[11] for setting the load following obligation based on the following formula:

[11] See SEM Consultation, Section 3.7.

$$\frac{(\textit{Actual demand} + \textit{Operating Reserve Requirements} - \textit{Capacity provided by plant without an RO commitment})}{\textit{Volume of RO sold}}$$

The formula is an attempt to adjust the obligation under the RO in line with the relative scarcity of capacity within the market at each point in time.

As the RAs acknowledge a major flaw with the proposed approach is in the treatment of plant without an RO commitment (“ineligible capacity”)[12].The proposed approach leaves suppliers unhedged by the amount of ineligible capacity supplied into the market. This is particularly problematic with exemptions applied to intermittent generation as suppliers are unhedged and the extent to which they are unhedged is unpredictable due to the intermittent nature of the ineligible capacity.

The ISO NE takes a different approach to the load obligation which addresses the issue of ineligible plants. The ISO NE’s proposed pay-for-performance scheme included all forms of capacity and therefore eliminates the issue of suppliers being unhedged.

The ISO NE defines its load following obligation by the following formulae, in which “Actual MW” means actual capacity provided, CSO stands for Capacity Supply Obligations and definitions of the other inputs are standard:

$$Performance\ Payment\ = Performance\ Payment\ Rate\ x\ Performance\ Score$$

$$Performance\ Score = Actual\ MW - CSO\ x\ Balancing\ Ratio\ (in\ \%)$$

$$Balancing\ Ratio\ (in\ \%) = \frac{\sum(Load + Reserve\ Requirement)}{\sum Capacity\ Obligations}$$

The Performance Payment Rate is the reward/penalty for variations in capacity set by ISO NE and is expected to be set at $2,000/MWh until 2021 after which it will increase. See Appendix B for more detail on the ISO NE load following obligation and pay-for-performance scheme.

As inspection of these formulae indicates, ISO NE takes a different approach to eligibility, including it in the definitions of both capacity requirement (the numerator of the Balancing Ratio) and the capacity obligations (the denominator). This formula can still have individual generators exposed to some risk, if their plant is temporarily unable to run, but at least their obligation is scaled down and the risk mitigated somewhat.

The scheme is similar to that proposed by the RAs in the SEM Consultation in that the quantity of the obligation is scaled according to the ratio of total capacity requirement (i.e. load/demand plus reserve margin) to the total volume of capacity obligations.[13] In the

[12] See SEM Consultation, Sections 3.7.4 – 3.7.11

[13] In the case of the pay-for-performance scheme the difference between the actual output of the capacity provider and this scaled capacity obligation is then multiplied by the Performance Payment Rate to determine the penalty/reward to be

circumstance where plant is unable to generate because it has been instructed by the TSO not to do so, this would have to take it into account in adjusting the capacity obligation.

In summary, while a load following obligation mitigates the risk associated with high price events occurring at times of system stress when demand is below peak levels and some plant is unable to run, the extent to which this aim is achieved depends on the broader scheme design. The load-following rules reduce the capacity obligation in order to mitigate the risk that generators are unable to generate at an unforeseen time of system stress when total demand is low. In practice, adjusting the capacity obligation pro rata does not provide a perfect hedging adjustment, since actual output depends on a merit order. This change in the circumstances facing generators imposes on them an additional exogenous risk, that needs to be accommodated in the system of capacity penalties. The omission of intermittent generation from the formula would leave some consumption unhedged, and problem that is resolved (at least in part) by including all generation in the calculation.

## 3.4. Conclusions

The principles of adaptability and stability promote economic efficiency by reducing uncertainty for market participants. Market participants are able to make more efficient decisions when they can predict future the market outcomes and the future of the market mechanism itself. The CRM will achieve more efficient outcomes if the RAs develop formulae or conceptual frameworks to reduce scope for regulatory discretion and provide greater certainty to market participants. For example, to maximise transparency and efficiency, the RAs should specify formulae that define how the capacity requirement is calculated and how de-rating factors for new and existing plants will be measured; as far as possible, these formulae should use observable public data (i.e. historical data, not someone's forecasts). For the sake of adaptability and stability, such rules should as far as possible be unrelated to specific technologies (which may change in future), but should refer instead to general operating characteristics (such as "non-despatchability") and plant-specific data.

The design of the CRM would benefit from industry input on the technical and plant-level data to be used in CRM formulae, organised as a workstream on capacity definitions.

applied. Under the RAs proposed scheme, the scaled capacity obligation is used to calculate the capacity which falls under the RO contract and therefore the payment that the capacity provider must make to the TSO.

# 4. Penalties, Rewards and Enforcement

This chapter sets out the need for penalties to enforce capacity obligations, and the role they play in ensuring the effectiveness of the capacity mechanism.

In principle, any capacity mechanism should be designed to observe the following economic constraints:

- **Incentive Compatibility constraint:** If the instantaneous penalties during individual events are too low, generators will sign Reliability Options (for a low price) but will not provide physical capacity when it is needed.
- **Participation constraint:** If the penalties can accumulate over extended or multiple events to a large amount (relative to generator margins), the capacity market will have to settle at high prices to cover the risk of high penalties. Investors may even be unable to participate in the market, and hence be deterred from making capacity available, by the risk of bankruptcy due to high penalties.

The choice of mechanism is often a trade-off between these constraints. For instance, large instantaneous penalties provide strong incentives to make capacity available at times of system stress. However, the most efficient scheme design may cap (or mitigate) total penalties over some period(s) to encourage higher participation. In the most efficient scheme design, neither constraint dominates the other, and the trade-off finally adopted may involve detailed rules.

We note in passing that it may be difficult to apply this constraint to ESB, which may not be motivated by the same attitude to risks and rewards as a privately owned company. However, we know of no easy solution to this problem. The constraints apply in any case to the privately owned companies that are present in the market, or which may enter in the future.

The remainder of this section addresses the specific design questions around setting and enforcing penalties, the rationale for exemptions and the treatment of intermittent generation.

## 4.1. Setting Penalties and Rewards

Penalties and rewards provide additional incentives for capacity provision at times of system stress by decreasing or increasing the revenues of the capacity provider in cases where they under/over-perform relative to their capacity obligation.

To provide an incentive at the margin, incremental penalties and rewards must adjust revenues by more than the incremental cost of making additional capacity available. If the penalties are too low in any instant, a generator may be willing to accept the penalties and not provide capacity, thus rendering the scheme ineffective.

The appropriate level for *total* penalties and rewards depends on the characteristics of capacity providers, e.g. their flexibility and reliability. If a generator cannot respond to incentives, no matter how strong they are, no purpose is served by imposing penalties beyond a certain level (particularly the level that would bankrupt the generator). Accordingly, it may be optimal to offer capacity providers who differ in their ability to respond to incentives different regimes of reward and risk, as long as those differences can be objectively justified by technological criteria and can adapt to changing circumstances in the generation sector (such as new or hybrid technologies emerging). This application of differing regimes of risk and reward arises in any circumstance where there is uncertainty around the level of effort being put into delivering some output. Indeed, in such cases the efficient outcome involves a degree of risk-sharing between the parties to the contract, a finding that is well-established in the economy literature.[14]

Financial penalties should also be supplemented with other enforcement mechanisms to maximise the effectiveness of the mechanism. The primary tool in this respect is basing future participation in the scheme on past participation. For example, the de-rating factors of capacity providers that do not perform during stress events can be reduced down to reflect their poor performance. In the extreme case, capacity providers could also be excluded from the mechanism by restricting participation in the auctions for capacity obligations. This is particular important if the capacity mechanism has caps on the penalties incurred that restricts the possibility of negative payments as a result of participating in the scheme.

## 4.2. Exemptions and Caps

Allowing exemptions from penalties has a large effect on the allocation of risk within the capacity mechanism. Extensive exemptions mute the incentives provided by the capacity mechanism while allowing insufficient exemptions would place substantial risks on some capacity providers.

A number of factors outside the control of a capacity provider influence its ability to make capacity available. Imposing penalties when such events occur serves no purpose in terms of incentives and creates additional risk that threatens the desire to participate in the market. In general there are two approaches to handling these events:

1. exempt capacity providers from penalties arising from events outside of their control; and/or
2. limit the total penalty that any capacity provide can incur over a certain period.

The first approach preserves incentives in all other situations, but will inevitably require the RAs to exercise a degree of discretion in adjudicating when such events have arisen. The second approach involves less discretion, and a number of schemes already provide examples of multi-dimensional limits (monthly, yearly and so on), but limits can dampen or eliminate incentives when they are breached.

In ISO-NE, the current scheme is akin to the first approach, whereby exemptions are given to capacity providers if their inability to provide capacity was a result of a factor outside their control. This scheme has come under criticism for not providing sufficient incentives to capacity providers and is largely blamed for the current reliability issues in the market.

[14] Cheung, Steven N S (1969). "Transaction Costs, Risk Aversion, and the Choice of Contractual Arrangements". Journal of Law & Economics. 12 (1): 23–42

The ISO NE's proposal to move to the pay-for-performance scheme will be a step away from risk mitigation, because capacity providers must bear some of these risks.[15] In addition, the pay-for-performance scheme removes the penalties that arise from interaction with the energy market, by cancelling the rebates known as "Peak Energy Rents". However, the scheme would still set a limit on the penalties that capacity providers can incur over various periods, as per the second approach.[16] The aim of setting multiple limits over multiple time periods is to ensure that penalties cannot be excessive either in the short run or over a whole year, but also if possible, that the limit imposed on excessive penalties incurred in one short period does not invalidate the incentive effect of penalties incurred in the *next* period. This is particularly important for unplanned short term outages for which it is not possible to perform a secondary market trade to adjust the RO contract position.

The approach to exemptions and caps on penalties in the I-SEM capacity mechanism takes on added significance due to the recent introduction of a provision allowing TSOs to re-declare the achieved capacity of a generator at the level of their effective availability during network outages. This proposal exposes generators who participate in the RO to the risk of network operations, over which they have no control. We see three possible methods for managing this proposal within the RO scheme:

1. pass through of the implications to *suppliers and consumers*, i.e. give explicit exemptions from penalty on those occasions where the TSO re-declares plant availability due to a network outage;
2. pass the penalty over *to the TSO*, i.e., make the TSO liable for the penalty payments incurred by the plant due to its network outages; or
3. leave the risk with *capacity providers* and require them to manage the risk as best they can.

In circumstances where capacity providers have no control over the network outage, placing the risk on capacity providers does not provide any sharper incentives but threatens them with potential financial problems and even bankruptcy. The most efficient outcome is likely to be a combination of all three possible methods, but with the main emphasis on method 1 (because the event should be objectively identifiable), perhaps some reliance on method 2 (if there are cases where it makes sense to maintain incentives, within limits) and very little use of method 3 (because it imposes risk but offers little or no improvement in incentives).

The final outcome will require detailed consultation with the industry over the precise nature of the risks, incentives and decisions involved.

## 4.3. Treatment of Intermittent Generation

Intermittent generators are fundamentally different from conventional generators as they are typically energy constrained rather capacity constrained, i.e. their energy output is limited by

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15 The supposed rationale for this move is that capacity providers are best positioned to assess and quantity the drivers of their ability to provide capacity and therefore should be responsible for pricing it. However, this argument seems to overlook the potential benefits of insurance, if the costs of some outages within a portfolio of generation are borne by suppliers in general, rather than their individual owners.

16 See SEM Consultation, page 115.

the exogenously varying availability of an energy source (wind, tides, sun, etc) and by not the fixed capacity of the generator turbine. As a result, operators have much less control over the power that intermittent generators can provide at any point in time. For this reason there is an economic rationale for treating intermittent generation differently.

Any special treatment needs to be consistent with regard to rewards and penalties. If intermittent generators have no control over the amount of capacity they provide, they have a case for being exempt from the penalties for not providing capacity. However, if intermittent generators are unable to guarantee capacity during stress events, they also have no grounds for claiming any payment or reward for making capacity available.

In general, the de-rating factor applied to intermittent generators ought to divide their capacity into eligible capacity (which can take on ROs, but which is subject to penalties) and ineligible capacity (which has a zero value in MW throughout the RO scheme). Thus, a 100 MW wind farm with a 90% de-rating factor consists of 10 MW of eligible capacity (which is treated the same as any other capacity in the RO scheme) and 90 MW of ineligible capacity (which is ignored by the RO scheme).

We note that there are few reasons for completely exempting any capacity from penalties for low reliability, since that is one of the factors contributing to insecurity of supply and the need for operating reserves. Allowing unreliable generators to escape all the consequences of their choice of technology would provide an implicit subsidy to those who are imposing costs on others, although their liability for penalties need not be unbounded, for the reasons given above. The caps on penalties should take into account the unmanageable risks faced by intermittent generators and the need to mitigate the total financial burden of such risks. Promoting renewables sources of generation may be a policy objective, but economic efficiency demands that the capacity mechanism should not introduce unnecessary distortions into the choice of technology, by unduly favouring particularly unreliable sources of generation.

## 4.4. Conclusions

Rewards and penalties based on performance during times of system stress are the fundamental drivers than ensure the CRM solves the “missing money” problem. RO settlement gives capacity providers no additional incentive other than the market price, so they may lack the incentive to provide sufficient capacity. In such circumstances, CRMs must be bolstered by additional penalties and rewards for providing more or less physical capacity during periods of system stress.

These rewards and penalties need to be targeted to encourage efficient decisions without creating unnecessary risks. The availability of any capacity may be affected by both internal and external factors – i.e. factors that are within the control of the plant operators (like maintenance) and factors that are outside their control (like the level of wind). When availability depends on external factors, then imposing penalties on capacity providers offers no additional incentive, whilst the additional risk of penalties outside their control discourages capacity providers from building capacity and participating in the scheme.

For instance, many CRM schemes put a cap on total penalties over short periods, to limit their financial impact on capacity providers. Such caps mitigate the risk of bankruptcy, particularly for unmanageable external risks that market participants cannot unwind through offsetting hedges. By doing so, they help to encourage participation in the CRM and hence to produce a more efficient outcome overall.

The design of the CRM would benefit from industry input on the economic and financial parameters used to define and limit rewards and penalties for providing capacity, organised as a workstream on enforcement.

# Appendix A. Italian Capacity Market Mechanism

The Italian Capacity Market Mechanism is a non-compulsory scheme for incentivising the provision of generation capacity. Capacity providers are given the opportunity to enter into Reliability Option (RO) contracts sold through annual competitive auctions. These contracts provide a fixed revenue stream to capacity providers to cover their fixed costs of making capacity available to the market. In exchange, capacity providers forego revenue received when reference prices are above the strike price of the RO contract they hold. RO contract strike prices are set on a regional basis with reference to the average variable cost of the marginal dispatched plant. Reference prices are also set regionally and therefore reflect the variations in system conditions across the network.

In order for a plant to be admissible into the capacity auctions it must not be intermittent, subject to any other type of investment incentive scheme or subject to any dismantling measures.[17] Prior to bidding into an auction Terna calculates an “expected available capacity” for each plant which provides an upper limit of the amount of capacity that can be bid into an auction for that plant.

## A.1. References prices

The Italian Capacity Market Mechanism covers bidding into both the day-ahead market and the dispatch services market and therefore uses a scheme for setting the reference price which seeks to combine the prices from these two markets while maintaining the appropriate incentives for capacity provision. Table A.1 outlines how the reference price is determined based on the bidding behaviour and dispatch outcomes for a capacity provider in the day ahead and dispatch services market.

**Table A.1**
**Bidding behaviour and determining the applicable reference price**

<table>
<tr><th colspan="2" rowspan="2">Quantity</th><th colspan="2">Spot price</th></tr>
<tr><th>Offered price ≤ strike price</th><th>Offered price > strike price</th></tr>
<tr><td colspan="2">Accepted on the Day-ahead market</td><td colspan="2">Price on the Day-ahead market (P_DAM)</td></tr>
<tr><td rowspan="2">Presented but not accepted on the Day-ahead market (DAM) and not presented on the Dispatch Sevices Market (DSM)<br>*or*<br>Not presented on the DAM nor on the DSM</td><td>Adequacy system</td><td colspan="2">Max (P_DAM; Max Price on the DSM)</td></tr>
<tr><td>Lack of adequacy system</td><td colspan="2">VENF</td></tr>
<tr><td colspan="2">Presented and accepted on the DSM</td><td rowspan="2">Strike price</td><td>Offered price</td></tr>
<tr><td colspan="2">Presented but not accepted on the DSM</td><td>Max (P_DAM; Max Price on the DSM)</td></tr>
</table>

Source: http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_12.pdf

The principle underpinning the design of the scheme is that capacity bid into a particular market should be settled against the price in that market. The scheme achieves this by

[17] Italian Capacity Market, Terna, Brussels, April 2015 http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_12.pdf

splitting the capacity under the RO contract according to which market each unit of capacity is bid into and is ultimately cleared. The quantity dispatched in the day-ahead market is settled against the day-ahead market price and then the quantity accepted in the Dispatch Services Market is settled against the Dispatch Services Market price. This split settlement process allows capacity providers to better manage their risks while still retaining the strong incentives associated with being exposed to the balancing market price. The remainder of this section summarises the incentive properties of potential outcomes under this split scheme.

In the circumstance where a capacity provider bids into the day-ahead market and their bid is accepted the reference price is set as equal to the day-ahead market price. In this case, a capacity provider is liable to repay the system operator when the day-ahead market price is greater than the RO contract strike price.

In the circumstance where a capacity provider does not bid into either the day-ahead or dispatch services markets or is not dispatched in the day ahead and then fails to bid into the dispatch services market then the applicable reference price depends on the prevailing system conditions.

If supply is adequate to meet demand then the reference price is equal to the maximum of the prices from the day ahead and dispatch services markets. In this circumstance, the capacity supplier is incentivised to bid into the market (either the day-ahead or dispatch services market) with the greatest likelihood of having a price that is greater than the contract strike price as this will minimise the likelihood of having to give a payment to the market operator. In other words, while ever there is a risk that the price in either market will exceed the contract strike price then a bidder is expected to bid into the market that values its capacity the highest. However, this exposes the generator to some basis risk, if its forecast of the market prices turns out to be the wrong way round.

If there is insufficient supply to meet demand - a so called ‘stress event’ - then the reference price is set to the Value of Energy Not Supplied (VENF). Under these conditions the price in the DSM is also set to VENF and so this is equivalent to settling the RO contract against the DSM price. In this case, since the VENF will always be greater than the contract strike price, the capacity provider is liable to pay the system operator the difference between the VENF and strike price. As the VENF is high relative to the strike price, the result of this pricing rule is that there is a very strong incentive to provide capacity during these stress events.

For capacity suppliers bidding into the dispatch services market, the applicable reference price is a function of both whether a bid was accepted or not and whether the price bid is greater than the strike price since the dispatch services market is pay-as-bid.

If the price offered into the dispatch services market is below the strike price then the reference price is set equal to the strike price (irrespective of whether the bid was accepted or not). The result being that no payment back to the system operator will ever be required under this circumstance. This is equivalent to making the RO a one-way or call option that uses the offer price as a reference price.

If the price of the bid offered is greater than the strike price, if the bid is accepted then the reference price is equal to the bid price. In this case, a capacity supplier is liable to pay the difference between their bid and the strike price and therefore may have a reduced incentive to bid above their short run costs of providing balancing/ancillary services. Finally, if the bid is not accepted then the reference price is set to the maximum of the prices in the day ahead and ancillary services markets. Since the bid was not been accepted on the DSM, the bid must have been higher than the DSM price, and highly likely to have been higher than the day-ahead market price.

## A.2. Auctions for Reliability Option contracts

The RO contracts are expected to be issued through annual auctions administered by Terna. The scheme provides three separate ways for capacity supplier's to obtain RO contracts, namely:

- Main Yearly Auction
- Adjustment auction
- Secondary Market

The main yearly auction is for the procurement of capacity four years ahead of delivery and for a delivery period of three years. The auction is run as a multi-round descending auction with the aim of issuing the contracts at the lowest possible price, as determined by the market. It is expected that the bulk of contracts will be issued through the main yearly auction.

The adjustment auction is an opportunity for capacity suppliers to adjust their position from the main yearly auction between 1 and 3 years in advance of the delivery year. It will also be conducted through a multi-round descending price auction. There is also expected to be an active secondary market whereby capacity suppliers can adjust their contract positions held through trades of one month contracts with other market participants. These transactions are expected to be conducted on an ongoing basis within a year of capacity delivery.

Owing to the significance of interconnector constraints in the Italian market, RO contracts will be issued on a regional basis through separate auctions. Capacity requirements vary greatly by region and so the value of capacity and therefore strike prices must vary to provide non-distortive price signals. The implementation of separate auctions reduces the level of competition in each regional auction and therefore potentially increases the likelihood that capacity providers have a degree of market power in procuring RO contracts.

## A.3. Financial hedging considerations

The complex mix of the day-ahead market price and dispatch services market prices in determining the reference price raises questions around the ability for market participants to appropriately hedge their financial exposure to the wholesale electricity price. The applicable reference price is largely determined by the behaviour of the bidder and which market they choose to bid into and therefore, bidders retain some control around which market prices they are exposed to through the capacity mechanism. Therefore, to a large degree the scheme design allows bidders to manage their financial exposure through traditional products based on either the day-ahead or dispatch services market prices.

# Appendix B. New England Capacity Market Mechanism

The ISO New England Forward Capacity Market (FCM) operates on the basis of a Capacity Supply Obligation (CSO), which is analogous to the concept of Reliability Obligations. Capacity Supply Obligations are allocated through auction processes known as the Forward Capacity Auctions (FCAs) and capacity providers receive payments equal to the price set through the auctions.

The FCM is currently undergoing reform with respect to the mechanism for incentivising the provision of capacity by capacity providers. The current scheme has come under criticism for not providing the appropriate incentives and so the ISO-NE over recent years has developed a number of amendments to the current scheme. Together these proposed changes are known as the pay-for-performance scheme. The current scheme and the proposed pay-for-performance scheme are discussed in the next section.

The FCAs occur every year and are used to allocate CSOs to capacity providers through a competitive process. Within the FCAs there is a mechanism for ensuring that capacity market meets the need of all regions of the network. To do this the network is split into import constrained zones, export constrained zones and the rest of the pool based on the supply, demand and transmission characteristics of areas within the network. These regions are reassessed periodically to take account of changing market conditions. For example, two zones were recently added for the FCA-10 to be held in 2016.[18] In import constrained zones, a local sourcing requirement is specified which is a minimum amount of capacity that must be procured in that zone. In export constrained zones a maximum capacity requirement is incorporated in the auction clearing mechanism.

## B.1. The Current and Proposed Capacity Market Incentive Mechanisms

ISO-NE is in a transition period with respect to its capacity market performance incentive arrangement. In February 2014, ISO-NE's proposed reforms to the capacity market, known as the pay-for-performance scheme, were brought before the Federal Energy Regulatory Commission (FERC) for approval. After revisions these new provisions were successfully passed through and are to be incorporated into the terms of the CSO's allocated from FCA-10, which will be held in February 2016.[19]

In its submissions to the FERC, ISO-NE claim that the previous FCM mechanism was not producing the appropriate incentives for capacity provision and this was leading to reduced performance of the fleet of generators in ISO-NE.[20] In particular, the numerous exemptions

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18 ISO New England Inc., Docket No. ER15-___-000; Identification of Potential New Capacity Zone Boundaries, 6th April 2015, http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13830206

19 Master Forward Capacity Auction #10 Schedule, February 2015, http://www.iso-ne.com/markets/othrmkts_data/fcm/auction_cal/2019_2020_master_fwrd_cap_auction_10.pdf

20 ISO New England Inc. and New England Power Pool, Filings of Performance Incentives Market Rule Changes; Docket No. ER14- -000 , http://www.cramton.umd.edu/papers2010-2014/er14-1050_000_1-17-14_pay_for_performace_part_1.pdf

from penalties, the fact that entering into a CSO did not involve any risk of negative payments and that the definition of scarcity conditions were triggered only after 30 minutes of scarcity meant that insufficient investment was being made in capacity and plant flexibility, leading to increased outages.

The ISO-NE proposed pay-for performance scheme separates the capacity market mechanism into two stages. The first stage is similar to the current auction process and involves the procurement of capacity to meet the expected load through the allocation of CSOs through the FCAs. The second stage involves performance payments based on whether a generator is providing capacity during a capacity shortage period, as defined over a 5 minute interval. These performance payments only involve transfers among participants; from capacity providers that are generating during the capacity shortage events to providers who are not. It also eliminates the many exemptions from penalties that previously applied, and therefore places sharper incentives on capacity providers irrespective of prevailing conditions.

For FCA-9 and previous auctions the scheme included a provision for Peak Energy Rent (PER). PER is payment back to the system in circumstances where the market prices exceed a defined strike price and therefore works in a similar manner to the payment profile under the Reliability Obligation. The ISO-NE has developed a further reform proposal to eliminate this PER as it is no longer required with the implementation of the Pay-for-Performance scheme as the scheme will provide sufficient incentives.[21] This change is expected to be implemented from FCA-10 onwards. Previously, the PER adjustment has been criticised for being a poor and incomplete hedge for energy purchasers and does not protect load against spiking fuel costs.

## B.2. Load Following Obligations in New England

The Pay-for-performance incentivises performance through the calculation of performance payments which vary in accordance with the system conditions. These payments are calculated using the following formulae[22]:

$$Performance\ Payment\ = Performance\ Payment\ Rate\ x\ Performance\ Score$$

$$Performance\ Score = Actual\ MW - CSO\ x\ Balancing\ Ratio\ (in\ \%)$$

$$Balancing\ Ratio\ (in\ \%) = \frac{\sum(Load + Reserve\ Requirement)}{\sum Capacity\ Obligations}$$

A key parameter for determining the strength of these incentives is the Performance Payment Rate. ISO-NE calculates the rate based on the Cost of New Entry and intends to phase in the rate as follows:

- $2,000/MWh for the period 1 June 2018 to 31 May 2021;

21 Peak Energy Rent (PER) Adjustment Mechanism - Proposal for FCA-10 and Beyond, February 2015

22 FCM Performance White Paper, October 2012, http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf

- $3,500/MWh for the period 1 June 2021 to 31 May 2024; and
- $5,455/MWh for the open-ended period starting 1 June 2024.

ISO-NE states that these capacity Performance Payment Rate is designed to achieve its loss-of-load probability standard of "one day in ten years", which is equivalent to about 2.4 hours of lost load per year on average.

Through these formulae, the payments under the pay for performance scheme vary according to the prevailing system conditions through the balancing ratio. The balancing ratio is defined as the ratio of the total capacity requirement (ie, the sum of total load and reserve requirement) to the total capacity obligations allocated. Therefore, at times of high demand, the total capacity requirement increases and consequently, so does the balancing ratio. This increase in the balancing ratio effectively increases the share of the CSO that is compared to the actual capacity provision when calculating the performance score and therefore decreases performance payments when supply is plentiful and increases payments when supply is scarce.

The pay-for-performance scheme creates particularly strong incentives for capacity providers to meet their obligations by limiting the scope to avoid penalties for under-provision. The scheme puts a cap on negative payments, but does not rule them out entirely, so participation is no longer a zero-cost option.

The lack of exemptions means that capacity provider must cost all of the risks that may cause them to fail to meet a capacity obligation into the bids in the capacity auction. These include risks associated with events outside the control of the capacity provider, such as being constrained off due to transmission outage.

## B.3. Treatment of Intermittent Resources in ISO New England

In the ISO-NE market, intermittent resources are allowed to bid into the capacity market auctions and are able to acquire Capacity Supply Obligation contracts in essentially the same manner as a conventional generator. However, in contrast to conventional generators, it is optional for intermittent resources to bid into the day-ahead market.[23] In assessing the capacity that can be bid into the FCAs the performance of the wind farm is taken into account and therefore a capacity significantly lower than the nameplate capacity is applied.

Under the current rules, intermittent generation is subject to the Peak Energy Rent adjustment where payments are made back to the system operators for revenues earned during periods of high prices. However, it is not subject to any further penalties for not providing capacity during peak events.

[23] Benefits/Risks of Having Capacity Supply Obligation (CSO), October 2014, http://iso-ne.com/static-assets/documents/2014/11/12_fcm101_oct_2014_capacity_supply_obligations.pdf

One of the key principles underlying the pay-for-performance scheme is that in contrast to the existing rules there are no exemptions[24] and therefore, under the proposed pay-for-performance scheme intermittent generators, such as wind or solar, are treated in the same manner with regards to their performance payments as any other generation resource. Respondents to the FERC assessment of the pay-for-performance scheme[25] argued that, because intermittent resources such as wind and solar are "predictably variable", then they can forecast the overall performance of these resources. Further, since intermittent resources are only allowed to bid a fraction of their nameplate capacity into the FCAs they can potentially exceed their CSO and attain positive performance payments.

24 ISO New England Inc., and New England Power Pool, Filings of Market Rule Changes To Implement Pay For Performance in the Forward Capacity Market, Jan 2014, http://www.cramton.umd.edu/papers2010-2014/er14-1050_000_1-17-14_pay_for_performace_part_1.pdf

25 Order on Tariff Filing and Instituting Section 206 Proceeding, Paragraph 79, http://www.iso-ne.com/regulatory/ferc/orders/2014/may/er14-1050-000_5-30-14_pay_for_performance_order.pdf

# Appendix C. Incentives Under a Blended Market Reference Price

This appendix presents a theoretical example based on section 3.6.22 of the I-SEM consultation document. We show that the blended reference price can provide muted incentives through providing a marginal price to capacity providers that is less than the balancing market price.

Consider the circumstance similar to that defined in the example in section 3.6.22. A capacity provider has not bid its full capacity into the day-ahead market as it believed that the expected price was lower than its short run marginal cost (SRMC) for some of its capacity, at least. A network outage has occurred and so the balancing market price is now expected to be higher than their SRMC and so the capacity provider plans on bidding into the balancing market.

We first define the revenue equation for a generator under a blended market reference price:

$$Revenue = P_D.Q_D + P_B.Q_B - \max\left[\left[\left(\frac{Q_D}{Q_D+Q_B}.P_D + \frac{Q_B}{Q_D+Q_B}.P_B\right) - S_P\right], 0\right].Q_R$$

where $P_D, P_B$ are the prices in the day ahead and balancing markets respectively and $Q_D, Q_B, Q_R$ are the quantities of capacity offered into the day-ahead market and balancing market and the quantity under the Reliability Obligation, respectively. $S_P$ is the RO strike price. As in the Italian example, the relative weights of each market are specific to each capacity provider.

To find the marginal effect on revenue of the generator offering additional output into the balancing market we calculate the derivative with respect to $Q_B$, the quantity offered into the balancing market. This gives:

$$\frac{\partial R}{\partial Q_B} = P_B - \frac{Q_R Q_D (P_B - P_D)}{(Q_D + Q_B)^2}$$

In the example $P_B > P_D$ and so if we assume that the RO is called:

$$Q_R > 0$$

$$Q_D > 0$$

$$\left(\frac{Q_D}{Q_D+Q_B}.P_D + \frac{Q_B}{Q_D+Q_B}.P_B\right) > S_P$$

we get a positive deduction from $P_B$ on the right hand side, and so:

$$\frac{\partial R}{\partial Q_B} < P_B$$

This result shows that under the blended market reference price approach, when a rebate is being paid, the additional revenue received from offering an additional unit of capacity into the balancing market is less than the balancing market price. The additional unit of capacity both increases the revenues from the wholesale market and shifts the reference price by changing the relative weights applied to the day-ahead and balancing markets.

For example, let $P_B = €300/MWh$, $P_D = €150/MWh$, $Q_D = 40$, $Q_B = 25$, $Q_R = 80$. Assume that the RO is called and a rebate is being paid (if, as the RAs do, we assume $\mathrm{S_P} = €200/\mathrm{MWh}$ then this will be the case). The revenue received for an additional unit of capacity is then less than the Balancing Market price, being given by the following formula:

$$300 - \frac{80 \text{ x } 40 \text{ x } 150}{65^2} = €186/MWh$$

This muted incentive only occurs in a scenario where a RO rebate payment is made. With a higher strike price the significance of this disincentive declines, as events where the MRP is greater than the strike price are less frequent.

# Appendix D. Contracting and Basis Risk

This Appendix provides a formal description of financial flows under the RO and the implications of a scenario where trading and RO settlement occur in different markets.

In the case shown in **Box 1**, the reference price is the DAM price and the generator trades its total output in the DAM (incurring no imbalance charges). This example does not create any basis risk because the Market Reference Price for ROs is the same as the wholesale price paid or received by market participants. The CFD between the generator and supplier includes a provision whereby the difference payment is defined by the difference between the *contract strike price (C)* and the *DAM price (D)* only when D is less than or equal to the RO strike price (S), as shown in the top half of **Box 1**. When D rises above S during periods of system stress, as in the lower half of **Box 1**, the difference payment is defined by the difference between the *contract strike price (C)* and *the RO strike price (S)*.[26]

**Box 1: Financial Flows under an RO and CFD per MWh**

**C = CFD Strike Price** **D = Day-ahead Price**
**S = RO Strike Price**

| **Price Case** | | **Generator** | **TSO** | **Supplier** |
|---|---|---|---|---|
| **D ≤ S** | | | | |
| | Spot Mkt. Payments | D | | -D |
| | CFD Diff. Payments | C - D | | D - C |
| | Net Flows | C | 0 | -C |
| **D > S** | | | | |
| | Spot Mkt. Payments | D | | -D |
| | CFD Diff. Payments | C - S | | S - C |
| | RO Diff. Payments | S - D | D - S | |
| | RO Pass-through | | S - D | D - S |
| | Net Flows | C | 0 | -C |

This adjustment to the CFD contract is required so that difference payments under the CFD are aligned with the actual revenue from the wholesale market net of the difference payment under the RO. In addition, as discussed in the SEM Consultation[27], the generator's RO difference payment to the TSO must be passed through the supplier to avoid imposing an unhedgeable risk on the supplier. Without these adjustments, the net payment from supplier

[26] The latter outcome can be achieved either by redefining the net difference payment in the CFD, or by the buyer giving the seller a call option with a strike price equal to S, the strike price in the RO. The CFD then imposes a difference payment of C-D on the seller, while the option awards the seller D-S, leaving the seller a net payment of C-S.

[27] See SEM Consultation, Section 3.1.4

to generator during periods of system stress would not be the fixed CFD strike price (C), but rather a more variable amount, namely: C+S – D.

**Box 2** shows another, extreme, scenario where a generator sells all of its output into the Day-Ahead Market at the DAM price (D), but the MRP is the price in the Balancing Market (B). When the RO is exercised, as in the middle section of **Box 2**, a basis risk emerges that is equal to the difference between the DAM price and the BM price (i.e. equal to D-B).

**Box 2: Financial Flows under an RO and CFD – Selling at a different price from the MRP and the effect of a modified CFD**

**C = CFD Strike Price** | **D = Day-ahead Price**
**S = RO Strike Price** | **B = Balancing Price**

| **Price Scenario** | | **Generator** | **TSO** | **Supplier** |
|---|---|---|---|---|
| **B ≤ S** | | | | |
| | Spot | D | | -D |
| | CFD | C - D | | D – C |
| | Net Flows | C | 0 | -C |
| **B > S** | | | | |
| | Spot | D | | -D |
| | CFD | C - S | | S - C |
| | RO Transfer | S - B | B - S | |
| | RO Pass-through | | S - B | B - S |
| | Net Flows | C + (D-B) | 0 | -C - (D-B) |
| **Modified CFD** | | | | |
| **B > S** | | | | |
| | Spot | D | | -D |
| | Modified CFD | C - S - (D-B) | | S - C + (D-B) |
| | RO Transfer | S - B | B - S | |
| | RO Pass-through | | S - B | B - S |
| | Net Flows | C | 0 | -C |

Specifically, when the balancing price is higher than the day-ahead price (i.e. D-B < 0), as would be expected during an unexpected transmission network outage, the capacity provider's net revenue falls. This variation in revenue represents a problem for risk management by generators and suppliers alike.

In a circumstance where trading in the DAM is compulsory, adjustments to CFDs could account for the risk associated with exposure to the difference between prices in the Day-Ahead and Balancing Markets. As with the adjustment to the CFD to account for the RO payment, market participants could adjust their contracts to allow a generator to pass through to a supplier the difference between the day-ahead and balancing market prices. A the bottom of **Box 2** we provide an example of the adjustments to a CFD contract necessary to ensure that market participants effectively manage their risk in a scenario where the market rules force market participants to trade in the DAM and the MRP is the BM. We have termed this the 'modified CFD' approach.

A more likely outcome is described in **Box 3** (which echoes **Box 1** with the BM price replacing the DAM price). In this scenario, trading by the generator and supplier has moved to the BM and CFD contracts are now struck against the BM price. This shift from the DAM to the BM eliminates the basis risk that occurs when the strike price is called as there is now no exposure between the price differential between the two markets.

**Box 3: Financial Flows under an RO and CFD per MWh – MRP from BM**

**C = CFD Strike Price** **B = Balancing Market Price**
**S = RO Strike Price**

| Price Case | | Generator | TSO | Supplier |
|---|---|---|---|---|
| **B ≤ S** | | | | |
| | Spot Mkt. Payments | B | | -B |
| | CFD Diff. Payments | C – B | | B - C |
| | Net Flows | C | 0 | -C |
| **B > S** | | | | |
| | Spot Mkt. Payments | B | | -B |
| | CFD Diff. Payments | C - S | | S - C |
| | RO Diff. Payments | S - B | B - S | |
| | RO Pass-through | | S - B | B - S |
| | Net Flows | C | 0 | -C |

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