Response by Energia to SEM Committee Consultation Paper SEM-16-052

I-SEM Capacity Remuneration Mechanism Locational Issues Consultation Paper

22 September 2016

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1. Introduction and Overview

This document sets out Energia's comments in response to the Consultation Paper on I-SEM CRM Locational Issues dated 24 August 2016 ("the Consultation Paper")[1], including answers to the questions posed within that paper. Energia would be happy to answer any questions about this response or to arrange a discussion with our advisors, should the RAs require any clarification of our comments.

The views expressed herein should be considered preliminary given the lack of sufficient detail in the Consultation Paper and the overly compressed consultation period of just four weeks in which to respond[2]. We would encourage the Regulatory Authorities (RAs) to provide more information where indicated necessary and to further engage with respondents to elicit more fully informed views. This is critically important in the context of formulating a successful State aid notification and ensuring continued security of supply.

Expert Third Party Economic Appraisal

In support of this response, we submit a Memo from NERA (the "NERA Memo")[3], giving an independent expert assessment of the proposals presented in the Consultation Paper. The NERA Memo constitutes an integral part of this response and should therefore be read in full by the RAs. However, it is worth noting here just some of the many concerns NERA have raised:

All options are incompletely specified and their appraisal is unsound

"The proposed set of options (A-E) are under-defined…because they do not specify clearly how the SEM Committee will identify units that must not exit and provide them with incentives to remain operational. This makes it difficult for market participants to distinguish between the various options and to appraise them in detail". [NERA Memo, section 1]

"…the omissions from certain options give a misleading impression of the way in which they work, e.g. of the competitiveness or transparency of the overall process, or the efficiency of the outcome. This lack of the required detail, or of any recognition of the risks inherent in the lack of detail, make it impossible to conduct any meaningful appraisal…". [NERA Memo, section 2.2.3]

There is no sound, objective basis for SEMC's preference for Option C

"An undefined option, like Option C, always has an advantage over an option that is better understood, because the problems it will face are also undefined. … [R]elying on the difference in depth of explanation of different options (in other words, their relative vagueness) is not a sound basis for decision-making. There are certainly no grounds for favouring Option C just because all the other options seem to face known problems whilst Option C is so poorly specified that its

[1] Consultation Paper "Capacity Remuneration Mechanism Locational Issues", SEM-16-052, 24 August 2016.

[2] Significantly shorter than regulation guidelines of both the UR and the European Commission, as well as other policy consultations under I-SEM.

[3] NERA Memo (2016), "CRM LI Consultation – Evaluation", 22 September 2016.

problems are unknown. Unfortunately, that seems to be the sole basis of the RAs' preliminary view (as set out paragraph 3.2.49)". [NERA Memo, section 2.1]

"… because the appraisal criteria have not been applied on a consistent basis to all the options as described in the CRM LI Paper, the RAs' stated ("preliminary") preference for Option C as a "logical interim solution" is not soundly based." *[*NERA Memo, P.8]

A partial and skewed assessment of the options in relation to State aid has been carried out

"In relation to the options, the RAs note that Options A, B and E all involve explicit contracting by the TSO outside the market (and, in the case of Option B, in addition to it). In contrast, paragraph 3.2.32 says that Options C and D "could be more compatible with the State aid guidelines". That conclusion can only be based on the view that an automated process (i.e. the constrained solution algorithms used in these options) would be more acceptable to the EC than contracting outside the market. However, there is no reason why the EC would look more favourably on selective interventions in an algorithm (especially the "heuristic" kind used in Option C) than on direct negotiations with selected generators carried out in accordance with "clear and objective criteria". Furthermore, this conclusion overlooks completely the ex post interventions that would be required to address inaccuracies in the outputs of these algorithms (even those augmented by the DS3 process). This new "internal market" criterion has therefore been applied partially and selectively…". [NERA Memo, section 2.2.1]

Practical difficulties of modelling constraints in the auction mechanism

"… the RAs do not consider the possibility that the version available in time might be so simple or arbitrary as to lack all credibility or usefulness, if it produces outcomes that are unstable (i.e. affected by small changes in input data), unpredictable (if no-one understands how the "heuristic" rules will perform) or discriminatory (because some of the rules are clearly intended to include or exclude certain units, without any clear justification). In these circumstances, mere "practicality" (i.e. having some sort of algorithm in time) would be a hollow victory." [NERA Memo, P8]

"…options that produce no unconstrained schedule offer no basis for defining a single, objective market-wide reference price for capacity. Any market price resulting from a constrained auction would be distorted by the inclusion of specially selected plant in constrained locations". [NERA Memo, P2]

"Consideration of transmission constraints is required subsequent to any auctions (ex post) to ensure that the CRM results in a pattern of generation capacity which is feasible and will allow the system to operate. As our discussion above indicates, it is not clear that there is anything to gain from including constraints in any auction process, particularly the T-4 auction which will occur four years before the period of delivery. The TSOs may be able to identify cheaper solutions than procuring additional capacity from the bidders in the T-4 auction, such as reinforcing the network." [NERA Memo, P14]

Cost recovery is required for constrained-off and constrained-on plant:

"The SEM Committee's initially-favoured positions may deny cost recovery for constrained-off and constrained-on plant, and reduce efficiency. Compensating constrained-off plants may be necessary if these plants have a legal right to firm transmission access (either contractually or based on a concept like legitimate expectations), or it may be required to deliver efficient investment in the transmission system. Failure to compensate constrained-off plant may distort bidding incentives and reduce efficiency…" [NERA Memo, section 1]

"Providing incentives for market participants to distort their bids and to depart from cost-based bidding is unlikely to result in an efficient mix of plant on the system. Compensating constrained-off plant at the market price, equivalent to running an auction that ignores transmission constraints, as proposed in option B, removes this incentive to distort bids." [NERA Memo P. 13]

NERA's views on market power

"Capping prices at Net Going Forward Costs for constrained-on plant with local market power may not only deny cost recovery, but may also threaten security of supply and may be discriminatory". [NERA Memo, P.2]

"None of the proposed local market power controls in the capacity market prevent predatory bidding. … ESB is likely to be present in constrained areas. As a state-owned generator, it may not face the same commercial pressures as its privately-owned rivals, and may therefore be able to engage in predatory conduct, meriting its consideration by the SEMC." [NERA Memo P.19]

"There are … problems with the proposal to cap prices for participants in constrained areas at their Net Going Forward Costs and below the Uniform Price-taker Offer Cap. The resulting prices will not allow the affected plants to earn revenues that contribute to the sunk costs of efficient investment. The result may also be inefficient closure and threats to security of supply. The policy of applying a lower cap than the general one also appears to be discriminatory. [NERA Memo P.19]

Expert Third Party Legal Appraisal

We have also taken legal advice from Arthur Cox with regards to Grid Code requirements and in respect of State aid which is described in the Consultation Paper as *"[f]undamental to the SEM Committee's consideration of the proposals"*. The key legal issues arising from the RAs' approach to State aid and the Grid Code requirements are as follows:

State aid

- Insofar as the application of State aid requirements is concerned, it appears that the CRM being put in place will be financed through State resources so that the beneficiaries of the capacity remuneration payments (most notably payments under the RO contracts) will be considered to be in receipt of State aid. The RAs note in the Consultation Paper that "*fundamental to the SEM Committee's consideration of the proposals are the European Commission State Aid Guidelines, particularly in light of the ongoing EC energy sector inquiry including capacity mechanisms. Furthermore, we are actively engaged with the Departments (DCCAE and DfE) and the European Commission as we develop the capacity market design as ultimately EC approval is required for the CRM auctions to* *commence".* Despite this statement emphasising the importance of compliance with State aid requirements, there is no explanation of the RAs' understanding of the constraints that State aid rules impose on them in terms of the design of the CRM including as regards the treatment of locational issues. Furthermore the lack of detail as regards the options being considered, including as regards the financing of "out-of-market" aspects, make it impossible to assess fully the options put forward by the RAs including in terms of the relevance of State aid requirements and their application as the case may be. Detail is markedly lacking as regards the potential role to play by bi-lateral contracts as referred to at para. 2.4.5 of the Consultation Paper.

In this context, we have serious concerns that the State aid rules are being relied upon in the Consultation Paper to dismiss or undermine the options which do not have the favour of the RAs, without however a full consistency and compliance analysis having been undertaken by the RAs of each option by reference to the requirements that the RAs understand must be complied with under State aid rules.

For example, why the RAs believe that there "*may be State aid complications with units taken out of the market"* in their assessment pp. 26-27 and at para. 3.2.29 of Options A and E is not explained. No explanation is provided to support the RA's assessment that "*Options C and D could be more compatible with the State aid guidelines".* Similarly, the RAs' view that "*another key issue with Options 2 and 3* [concerning the remuneration of unsuccessful in-merit bidders] *is State Aid"* because "*it could be construed as payment for a service for a service which a generator is then not able or obligated to provide"* appears to be based on a very superficial analysis which does not recognise that the assessment of a State aid measure or scheme by the European Commission is carried out having regard to all aspects of the measure and its suitability to achieve the objective being pursued.

- In this regard it is Arthur Cox's legal advice that the assessment to be conducted by the European Commission for the purpose of State aid will not stop at whether some units are being remunerated that are out of the market and simply seek, as the RAs seem to suggest, to ensure that all arrangements are auction-based. Under the principles set out in the Environmental Protection and Energy State Aid Guidelines, the European Commission will examine among others whether the notified State aid scheme is suitable and appropriate to address the market failures arising and does not compound the issue that is sought to being addressed, has the right incentive effect and does not unduly affect competition. This very concrete assessment requires that the characteristics of the system in its entirely are taken into account, including in the case of the all-island electricity market, the fact that it is a highly constrained but relatively small market displaying dominance issues and with a high penetration of renewables.

  Energia is concerned that this exercise has not been carried out in full. In particular, it is not clear that sufficient attention has been given to the reasons for the locational issues arising and whether, from a very practical perspective, it is in fact possible to address, and rectify, them by way of the CRM in a manner that is consistent with the requirement of the State aid Guidelines.

Grid Code requirements

The RAs state in the Consultation Paper that as a result of the current requirement in the Grid Code to give the TSOs a three year notice of an intention to close capacity, a generator unsuccessful in the capacity auction would nevertheless be prevented from exiting the market. We have received legal advice from Arthur Cox that the RAs may not reasonably or lawfully rely upon the existing three years' requirement when devising the CRM unless they provide for adequate remuneration during those three years:

- There appears to be no specific reason for the current length of the notice requirement and none has been offered by the RAs. In these circumstances the RAs may not assume the application of the three year notice requirement but rather consider whether it continues to be justified and/or required having regard to the CRM design being proposed.
- The three years' notice requirement in the Grid Code is entirely at odds with the objectives being pursued in the CRM design, including in particular that generators receive appropriate exit signals. There is no purpose for a requirement that generators which should exit should remain for an additional three years' period. The RAs may not lawfully and reasonably design a CRM that is intended to encourage generators to exit and then prevent them from exiting.
- A design whereby generators are obliged by the Grid Code to give a three year notice including where they may not receive adequate remuneration in respect of their licensed activities is unfair and unreasonable and also contrary to the RAs' statutory duty to have regard to the requirement that that generators are able to finance their licensed activities and contrary to the constitutionally protected right to property.
- If the RAs consider that a three year notice is required, then they must allow, and provide for, the adequate remuneration of the generators concerned during the three year period.

1.1. The highly constrained, small market problem

I-SEM is a small market, with a substantial and growing penetration of intermittent wind and a structural market power issue. Its physical power system is highly constrained with only limited interconnection to the GB market. These unique characteristics of the I-SEM (see Annex 1 for details) do not make it an easy match for typical market mechanisms. For example, a common way to deal with system constraints is to fragment the market to approximate major locational issues. While this approach works well in large, competitive markets, it does not work for the I-SEM given the small size of the market combined with its high degree of market concentration which results in local markets that are either too small to support competition, or overly concentrated. These issues are acknowledged in the Consultation Paper in para.5.3.3 where it is stated that *"[t]he existence of locational constraints would tend to make the CRM auction less competitive because the effective market within each constrained area would be smaller and thus more highly concentrated"*, and in para. 2.4.3 which states that *"…the use of three or more* *capacity delivery constraints within the CRM might not be practicable or efficient, and could undermine the viability of the CRM as an effective market-based mechanism"*.

While the preferred solution to locational issues in the CRM is to try to incorporate a subset of physical transmission constraints within the auction clearing mechanism, this creates a number of serious issues (as discussed in detail later). The only alternative is to implement unconstrained market mechanisms, consistent with the SEM HLD, in the knowledge that local issues are inevitable and will have to be addressed in other ways[4] - e.g. in the case of I-SEM bilateral contracting,[5] as well as 'out of market' locational signals such as connection policy, GTUoS charging, TLAFs, etc.

1.2. Risk of inappropriate exit

Energia has consistently raised a concern about the significant risk of locational issues leading to inappropriate exit under I-SEM and DS3[6]. This is because these market designs, likely to sharpen exit signals, employ largely *unconstrained* mechanisms and therefore lack locational market signals, despite the power system being highly constrained. The need for unconstrained market mechanisms in the context of I-SEM is explained in section 1.1 above, but this gives rise to potential market failure at a local level,[7] resulting in the need for the TSOs to enter into bilateral contracts to secure "must-not exit" units[8] that are de-selected by the unconstrained market but that are needed for system security.

The TSOs clearly share our concerns regarding the risk of inappropriate exit. In their recent paper outlining the proposed de-rating methodology they state that "*a CRM auction result that satisfies the de-rated capacity requirement will not necessarily allow the TSOs to operate the power system within its operational limits while still satisfying the LOLE standard*"[9]. They also caution that "*the loss of load expectation could be higher than predicted if the theoretical available capacity from a portfolio of generators cannot be delivered due to transmission or security limitations*"[10]. It is noteworthy that these risks are not described by the TSOs as temporary or transitional. Accordingly, there is significant risk of inappropriate exit that must be addressed. Importantly, bilateral contracting by the TSOs to ensure system security will be required under any option put forward in the Consultation Paper, either due to the simplified nature of constraints modelled in the options, or the dynamic and unpredictable nature of system constraints that may change due to market conditions, such as generator or interconnector outages, or outages on transmission system assets.

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[4] For example, the current SEM design utilises an unconstrained ex-post market schedule with a constraint payment mechanism to provide compensation to generators for being moved to provide ancillary service or to manage binding system constraints.
[5] This need is acknowledge in the Consultation Paper in para. 2.4.5.
[6] See for example Energia response to SEM-15-044, especially pages 14-15.
[7] Market failure at a local level is a shortage of a particular service or product behind a transmission constraint. This can coincide with a general surplus of generation capacity .
[8] "Must-not exit" units are units required to provide services in specific geographical locations.
[9] See "I-SEM Capacity Remuneration Mechanism: Proposed Methodology for the Calculation of the Capacity Requirement and De-rating Factors", page 36.
[10] P.36

It should also be recognised that the risk of inappropriate exit is magnified by competition issues in the I-SEM – i.e. the level of concentration in the market. For example, the design of the CRM itself favours the State owned incumbent, ESB, by allowing it to diversify risk across its large, diverse generation portfolio. This could result in a significant reduction in the risk premium associated with less reliable generation assets within the ESB portfolio, allowing such units to submit relatively lower offers and displace more reliable generation assets owned by their competitors that may be required for system security reasons. ESB will also have a significant information advantage relative to its competitors when participating in the capacity auction on account of its large portfolio of generators. Given the state ownership of ESB there is also the risk, globally and in constrained areas given that none of the proposed market power controls address predatory bidding, that its offer submissions in the CRM will be influenced by non-commercial considerations[11] - e.g. set below costs to keep uneconomic units open to avoid industrial action (see section 6.2.5 of NERA Memo). The potential distortion of the capacity market that may result could further increase the risk that "must-not exit" units owned by ESB's competitors do not clear in the CRM auction.

I-SEM and DS3 consultation proposals and regulatory decisions have also compounded the risk of inappropriate exit by, *inter alia*:

- Failing to incorporate locational signals in the scarcity or product scalars for DS3 [DS3 Scalars Consultation, 11 March 2015]
- Inappropriately targeting perceived 'local' market power through restrictive bidding rules which could undermine revenue adequacy for constrained on generators[12]. [Market Power Decision SEM-16-024]
- Neglecting to target the wider competition issue associated with ESB's structural dominance even though the SEM Committee conclude that "the market concentration of ESB remains a concern…" [Decision SEM-16-024]
- Suppressing capacity prices artificially as a result of regulatory proposals which appear to be favoured merely because they produce low prices rather than competitive market prices (for example artificially low price caps and bid limits, with no bid caps). [CRM Consultation 3, SEM-16-010]

Energia has always advocated the need for a mechanism to facilitate some form of bilateral contracting by the TSOs to ensure the delivery of a secure power system. We therefore welcome the SEMC's recognition of the pressing need to address locational system security concerns in the Consultation Paper. However, as discussed in more detail later in this response, Option C as an interim measure and Option D as an enduring solution are not appropriate methodologies to address these concerns. Moreover, we

[11] Auctions for DS3 (as proposed in the DS3 HLD) would be prone to the similar issues and would further magnify competition problems in the capacity market.

[12] Faced with a revenue adequacy problem, and in the absence of a contract, the only way for a valuable generator behind a transmission constraint to cover its costs is to raise its offer prices in the balancing market, this should not be prevented by bidding rules (yet to be specified) that will apply to non-energy actions (and possibly energy actions) in the balancing market. For detailed discussion of this concern please refer to the market power discussion in section 2 of this response.

recommend that further careful consideration is given to ESB's structural market power under the I-SEM and DS3 market designs. Finally, we would emphasise that the design of local market power controls ensures adequate remuneration of generators that are required for reasons of system security to prevent further undermining security of supply.

1.3. The need to compensate "constrained-off" capacity

If the SEMC proceed with a decision that results in "constraining off" generators without compensating them[13] it will have a detrimental effect on investor confidence and financeability in this market. It will undermine incentives for efficient investment in the transmission system, will act as a barrier to future investment in generation, and is highly likely to be disputed by disaffected parties. These issues are discussed further below.

The incentive for the RAs and TSO to efficiently manage, and invest in, the transmission system requires an accurate and transparent valuation of the cost of system constraints. Such a valuation will only occur if "constrained off" generators in a capacity auction are properly compensated – i.e. either by the award of a capacity contract via an unconstrained auction, or the implementation of an appropriate compensation mechanism. Removing this important market determined signal by denying compensation for constraints will significantly undermine incentives to efficiently manage, and invest in, the transmission system. Taken in conjunction with the heightened perception of regulatory risk that would accompany it, such a policy change would impose significant long term costs on consumers.

Energia has consistently maintained that the SEM as an *unconstrained* market should have clear and strong locational signals. During the lengthy debate on Transmission Loss Adjustment Factors (TLAFs) over the period from 2009 to 2012 we put forward the rational thesis that locational signals should be strengthened, not weakened[14], as was particularly apparent following the investment of generation assets in the wrong location. The topography of plant on the system today is a direct reflection of the historic locational signals regime the RAs and TSOs put in place, and chose to weaken rather than strengthen (e.g. compressed TLAFs).

Therefore delivering a sharp, unanticipated locational exit signal to "constrained-off" generators in the midst of their investment cycle, as would be the case under options C and D, as well as options A and potentially E, represents a fundamental change to the established regulatory framework. Implementing such a change would seriously undermine the revenue adequacy of the generators concerned and thereby substantially increase the perception of regulatory risk associated with investing in the all-island market that would persist well into the future.[15] This would dramatically increase the cost of capital and prohibit future investment in this market, undermining security of supply and increasing long term costs for consumers. Implementing 'competitive' market mechanisms that deliver sharp exit signals

[13] Either directly via the CRM auction mechanism (as in options C and D), ex-ante (as in option A), or ex-post (as could be interpreted as the intention under option E).
[14] See Energia response to SEM-10-039, SEM-11-098 and SEM-12-024 for details.
[15] There is also a substantial risk it could lead to the disorderly exit of "constrained off" units.

to “constrained-off” plant within their investment cycle[16] would also bring into clear focus any flaws in the historic locational signal regime.

It would be fundamentally unfair, and may be susceptible to legal challenge[17], to try to correct this historic error now by implementing a partially constrained capacity auction that could deliver inefficient exit signals[18] – i.e. by de-selecting units that may later be identified as “must-not exit” after a comprehensive analysis of system security requirements by the TSOs. Furthermore, a generator that appears to be unnecessary now may turn out to be valuable in the future, for reasons that cannot be envisaged at the time of a capacity auction, particularly a T-4 auction.[19]

1.4. Distinct services from “constrained-on” generators

The options put forward in the Consultation Paper propose the use of RO contracts for “constrained-on” generators in the CRM. However, given their locational requirement, the products being secured from “constrained-on” generators are fundamentally different from the products being secured from other generators via the CRM auction. They are of the form “deliver service X at location Y when Z happens” as opposed to the standard product being auctioned which is “deliver service X when Z happens”.

Therefore, another form of contract specifically tailored to the specific service required may be more appropriate, providing their terms are reasonable and do not impose excessive, difficult to manage, commercial risks[20]. We would also stress that for contracts to be effective in delivering system security the terms would need to ensure the recovery of fixed costs plus a reasonable rate of return, so that the contracted generator can remain open [21].

The above issue applies to all options presented in the Consultation Paper, but is a particular issue for Option C and D given that locational issues are integral to the auction clearing mechanism and the auction is specifically for the award of reliability options. We discuss this important point further in section 1.6 in the context of State aid.

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[16] Investment in this context refers not just to the initial investment in a plant but also the significant ongoing investment in its maintenance, operation and upgrade.

[17] For example, not to compensate constrained off generators would on its face appears to be non-transparent and discriminatory of generators which are best placed, according to the auction, to provide capacity to the system as a whole, as opposed to a particular location.

[18] Exit signals may be inefficient because they are determined by a simplified representation of system constraints as modelled in the options.

[19] For example: the catastrophic failure of another generator or a transmission facility; unexpected growth or decline in a major demand; changes in transmission operating standards. Therefore assumptions around forecast constraints used in auctions may result in spurious accuracy that could have unfortunate commercial consequences in the longer term, such as the inappropriate exit of units later required because of a change in system circumstances; a situation that could easily arise within a small, highly constrained market such as the I-SEM.

[20] Such risks would undermine revenue adequacy and therefore the continued operation of the generator.

[21] Any plant that fails to cover all its costs (including its costs of financing) is in imminent danger of insolvency. Even if the owners are prepared to bear losses for some time, the firm’s creditworthiness will suffer and fuel suppliers may no longer be willing to sell it fuel. The plant’s exit may therefore be precipitated by actions outside the control of those bound by the Grid Code.

1.5. Evaluation of Options for auction design

This section considers the assessment of the options put forward in the Consultation Paper. As a first observation, it is worth noting that a rigorous, detailed assessment of the options is not possible because they are only described at a very high level in the Consultation Paper. For example, in options A and B it is unclear what constraints will be modelled, while in options C no details are provided in relation to the heuristic rules that will be used. Option D does not provide details of the problem that will be presented to the MIP solver, or how it will be solved, while it is unclear from the description of option E whether the intention is to: (1) procure additional capacity to secure the system over and above the auction results; or (2) "constrain off" capacity to offset "constrained on" capacity. If it is the latter no details are provided as to how this would be done in practice. Nevertheless, an initial assessment of the options as presented indicates that Options C and D do not score higher than our recommended option for the reasons explained below.

In options C and D only a small subset of the physical system constraints are modelled. The outcomes from modelling a small subset of constraints may bear little resemblance to the outcomes required by the TSOs to ensure secure operation of the power system. It is by no means "obvious and clear" which constraints should be included to achieve this, or indeed if it can be achieved at all. No evidence of such analysis is presented in the Consultation Paper, despite the commercial consequences for generators and the TSOs of the decision to limit the type and range of constraints recognised in the capacity auction.

Furthermore, given the proposal to model only a small subset of the physical constraints on the system the auction clearing mechanism under option C or D could result in generation required for wider system security reasons actually being de-selected by the heuristic or algorithm. As options A and B also model a subset of the physical constraints on the system they are subject to the same concerns. Option A could remove a sub optimal set of units from the auction process, while option B could result in sub-optimal additional contracting of units under the capacity mechanism. These issues are not properly considered in the assessment of options A, B, C and D but they could have a material impact on their overall efficiency relative to a more straightforward approach such as the one we put forward in section 1.6 below – i.e. a hybrid of options B and E.

The Consultation Paper scores Options B and E negatively on competition grounds. However, it is not clear how these options fare any worse by this criterion than options C and D, particularly if objective assessment criteria are defined for the checks carried out under options B and E. Options B, C and E proceed with an unconstrained auction result that is then adjusted to reflect constraints. In option D the modelling of these constraints is fully integrated into the auction clearing and pricing mechanism. We note however the potential for unhappy losers, results that are difficult to understand, and unintuitive pricing outcomes (because constraints affect pricing) under options C and D, which would have a negative impact on competition.

Furthermore, the auction outcome in options A, C and D will be materially segmented by constraints, effectively fragmenting the market, and reducing the potential for competition. Under option B the auction process is simplified in comparison, the market is larger (potentially increasing the scope for competition) and the results are more intuitive (because the security check is auxiliary to the clearing process and does not impact the results). Providing option E does not result in the de-selection of auction winners it would fare as well as option B in its assessment against the competition criterion. It is therefore unclear why option B or our suggested hybrid option of B and E, would fare any worse from a competition point of view than options C and D, and indeed should rather score higher than those options. They also score higher when assessed against the practicality criterion, as they are significantly easier to deliver given the auction design is simplified considerably.

In relation to State aid (the Internal Market criterion as outlined in the Consultation Paper) we would agree that Option A scores poorly against this criterion given that capacity contracts are awarded prior to the auction process, however it is unclear why option B, or our suggested hybrid of options B and E, would fare worse than options C and D in the assessment against this criterion. It is not the case, as appears to be the view of the RAs, that the EEAG require, or even prefer, solutions for ensuring generation adequacy that are entirely auction-based. Rather, the EEAG require first and foremost that the objective being pursued is clearly articulated so that the appropriateness and suitability of the aid may be assessed against that objective. Regrettably the Consultation paper does not articulate which objective is being pursued as regards locational constraints. As a result the issues of generation adequacy and locational constraints are conflated and a single auction-based system preferred without adequate consideration being given to whether State aid is necessary and appropriate to address locational issues, and whether the auction-based CRM is suitable having regard to the characteristics of the all-island market.

For the following reasons, we do not believe that the auction mechanism proposed by the RAS under Options C and D in particular is in any way suitable to address and deal with locational constraints in the all-island market.

We note that incorporating constraints into the capacity auction, or using constraints to change the outcome of an unconstrained auction (the reallocation of capacity contracts), produces a different outcome from securing additional units for reasons of system security without providing efficient signals and/or adequately remunerating the services being provided. This is because, under the proposed CRM, ROs are triggered by global scarcity within one single capacity zone. Therefore, allocating an RO will not incentivise delivery of the locational service when it is required as this is not a requirement that is driven by global issues but rather by local considerations. As a result, embedding constraints into the auction more generally without dividing the market into capacity zones (which Energia accepts is not an appropriate option for I-SEM) simply distorts incentives as ROs address global shortages when struck against national energy price, whereas modelled system constraints will indicate a local requirement, delivery upon which is not properly incentivised under the RO. In other words, including locational elements in the auction without dividing the market into appropriate capacity zones mean that different products - a generic and a locational one – are inappropriately remunerated the same because the national energy price does not provide the proper basis for valuing, remunerating or enforcing a contract for capacity within a constrained zone.

Providing capacity in a specific location is a distinct service from providing capacity in general, where capacity in a specific location is necessary for system security reasons and therefore the price will necessarily be higher. In the Commission Staff Working Document accompanying the Commission's Interim Report of the Sector Inquiry on Capacity Mechanisms, the European Commission appears to accept that capacity remuneration mechanisms may be used to address a locational capacity problem where there is either not enough generation capacity located in that particular region or that region is poorly connected to neighbouring regions. In such cases, the electricity market is failing to provide the required investment in the right places or for sufficient transmission investments to mitigate any locational problem.[22] The Commission suggests however what is crucial for ensuring efficient locational signals for investment in generation and transmission, and the location of demand, is a more efficient definition of bidding zones. In particular, for electricity prices to appropriately signal local scarcity, the Commission says, the market area or bidding zone needs to reflect the technical limits of the transmission system and zones defined based on transmission constraints can allow zonal electricity prices to provide more accurate signals for the efficient location of generation capacity and electricity demand.[23]

This however bears no resemblance with what the RAs have proposed, and nor could it. While the preferred solution from the perspective of State aid and of the European Commission is the implementation of capacity zones, this is not a solution that is available in I-SEM for reasons discussed in section 1.1 of this response. The small size of the capacity market relative to the large size of capacity units, combined with the high number of constraints on the power system, when considered in the context of the dominance of ESB, means that further fragmentation would result in even smaller capacity markets that were too highly concentrated to support a competitive auction-based selection process. We note that a key requirement under the EEAG is that the State aid measure concerned, in order to avoid undue negative effects on competition and trade, should allow for the participation of a sufficient number of generators to establish a competitive price for the capacity and not unduly strengthen market dominance.

In the context of the Irish market, where a single bidding zone is used but the system displays locational constraints and market power issues, an auction based mechanism seeking to model some but not all of the constraints will distort competition and send inappropriate signals. As the European Commission has stated, the use of a competitive allocation process will not

[22] European Commission Staff Working Document accompanying the Interim Report of the Sector Inquiry on Capacity Mechanisms {C(2016)2107 final}, para 5.2.3.5.
[23] European Commission Staff Working Document accompanying the Interim Report of the Sector Inquiry on Capacity Mechanisms {C(2016)2107 final}, pp. 34-35.

always guarantee competition, in which case an alternative process is justified:

"When market power exists and it is not possible to extend participation in the mechanisms – due for instance to the poor development of the electricity network or of demand response – an administrative allocation process can be justified with a view to minimise the costs of the system."[24]

This does not mean in our view that an auction-based mechanism is inappropriate to achieve generation adequacy on the island of Ireland. Rather it means that having regard to the characteristics of the all-island market, locational constraints should not be addressed within the auction, but separately from the auction and outside the CRM, as part of the services to be procured by the TSOs for the purpose of ensuring system security. This has the benefit of allowing the efficient procurement of generation adequacy by running an unconstrained auction, minimising in accordance with the EEAG the amount of aid required using a "*competitive bidding process on the basis of clear, transparent and non-discriminatory criteria, effectively targeting the defined objective*"[25] and the effective and direct tackling of locational constraints by the TSOs. We note in this respect that the use of bilateral contracts, envisaged by the RAs at para 2.4.5 should not involve State aid and will therefore not be subject to prior clearance. This is because the procurement of system services would not involve the State, or the use of State resources, but rather the exercise by the TSOs of their commercial functions and financial resources, in a normal, albeit likely regulated, way. (This being the case does not of course prevent notification to the European Commission of the approach to be used for the purpose of dealing with locational constraints, including for the purpose of confirming that there is no State aid involved. We would be happy to engage further with the RAs on procedural aspects.)

Accordingly, dealing with locational constraints as part of ensuring system security avoids inefficient outcomes and provides the TSO with incentives to invest in the transmission system to avoid the more permanent locational constraints arising.

By contrast, under options C and D, and option E if some capacity is "constrained off" to offset "constrained on" capacity, system constraints would be driving the selection process for capacity contracts, limiting competition compared to the more competitive unconstrained capacity auctions under option B and our suggested hybrid of options B and E. As the NERA Memo concludes, options C and D are rated more favourably by the SEMC assessment because they are vaguely defined and there has not been a rigorous, objective attempt to identify the potential drawbacks associated with them.

A more detailed and rigorous assessment of the options is provided in section 2 of the accompanying NERA memo and our answer to question 3.6.1 below.

[24] European Commission Staff Working Document accompanying the Interim Report of the Sector Inquiry on Capacity Mechanisms {C(2016)2107 final}, para 5.3.4.2
[25] EEAG, para 229.

1.6. Recommended solution to locational issues

Any modelling of locational constraints directly in the capacity auction (as per Options C or D) will only represent what is likely to be a very limited subset of the overall constraints on the power system. It will nevertheless add significant complexity to the auction clearing processes, and potentially to the pricing mechanism, without producing a secure and feasible solution or removing the need for further ex post adjustments, as envisaged under para. 2.4.5 of the Consultation Paper. In light of this and the forgoing discussion, informed by the independent expert economic and legal advice provided by NERA and Arthur Cox respectively, Energia advocates a hybrid of options B and E whereby:

(1) Capacity auctions are run on an unconstrained basis;

(2) The TSOs then conduct an ex-post full system security assessment to identify any additional units, not selected via the CRM, but required for reasons of system security;[26]

(3) The TSOs carry out a bilateral contracting process to secure the continued operation of additional units to ensure the provision of services essential for system security.[27]

(4) For the avoidance of doubt, similar to Option B the continued operation of any additional units secured via bilateral contracts under this hybrid option would not result in de-selection of other 'in merit' capacity.

The only reason not to adopt this approach and to pursue the preferred options C or D would seem to be a desire to show, for the purpose of State aid clearance, that all decisions relating to the allocation of capacity remuneration are taken on the basis of a single, competitive auction. However, this is not in fact required under the State aid rules, or indeed in this case, compatible with the most efficient outcome, and therefore State aid rules, as a desire will not be fulfilled, since the proposed options recognise only a limited set of constraints.[28] Accordingly, the TSO would in any case have to assess the adequacy of the system and enter into ex post negotiations with generating units required for feasible and secure operation of the system that did not clear the CRM auction.[29] Any such negotiations, however, should of course be opened up to the widest possible range of potential providers. The desire to rely on a single, competitive auction therefore does not provide a compelling reason for selection of options C and D over any other because the additional complexity it creates for the auction process does not remove the need for bilateral contracting by the TSO. Furthermore, step 3 in our proposed hybrid approach has the additional advantage that it would allow contracts to be developed to address the issues highlighted in section 1.4 above if required.

[26] For the avoidance of doubt a full system security assessment by the TSO should include all constraints on the power system, including any arising due to locational requirements for the provision of system services. This is how reference to a full system security assessment should be understood throughout this response.

[27] This

[28] Paragraph 2.4.2, key principles (1) and (2).

[29] This problem will not be addressed by passing it over to the DS3 auction process, because the exact same issues will arise.

We note also that options C and D provide the opportunity not to compensate constrained off generators. This on its face appears to be non-transparent and discriminatory of generators which are best placed, according to the auction, to provide capacity to the system as a whole, as opposed to a particular location. Furthermore and in any event, this is a false economy based on short term opportunism that is clearly not in the long term interest of consumers. It will remove fundamental market signals that provide both useful information for regulation and the basis for incentives on the TSO to efficiently manage and invest in the transmission system and would have a detrimental effect on investor confidence and financeability in this market.

A detailed assessment of our recommended hybrid of option B and E against the SEM Committee's criteria is provided below:

Internal Market: The hybrid option consists of an unconstrained competitive auction. This auction awards contracts to the cheapest available sources. Separately, following the auction results and only in cases where there is a demonstrated need to keep specific units operational, the TSOs would engage in bilateral contracting. In all the options A-E, the TSOs are likely to need to sign bilateral agreements with plants which do not succeed in the auction but are required for system security – i.e. "must-not exit" units. This need arises because of the removal of constraints from, or the simplification of the constraints included in, the auction or the algorithm. As in these cases, the hybrid option will only require the TSO to procure bilateral contracts with units that are necessary for system operation in the light of all of the information provided by the auction. It is therefore unclear why our recommended hybrid option would score lower against this criterion than the preferred options C and D, which fragment the capacity market on the basis of a set of simplified constraints that are unlikely to deliver a secure mix of generation.

Transparency: As described in the NERA Memo in section 2.2.2, all the options A-E suffer from a certain lack of transparency, because the TSO must take action after the auction to secure the operation of "must-not exit" units. Options C and D entail an additional lack of transparency *before* the auction, because of the hidden TSO interventions behind the design of "heuristic" rules or constraints in the MIP solver and how these may impact upon auction outcomes. Potential transparency issues with our hybrid option could be greatly reduced simply by forcing the TSOs to publish details of the security analysis they will conduct prior to their selection of "must-not exit" units. Whereas the perceived benefits attributed to options A and B based upon their transparency require the simplification of the constraints applied undermining the efficiency of these options. Regardless, it is unclear why our recommended hybrid option would score lower against this criterion than the preferred options C and D.

Efficiency criterion: – The outcomes of options A, B, C and D all rely on simplified assumptions made prior to the auction, about the location and likely level of constraints on the system. As a result they may over-procure capacity in some locations and may still require the TSOs to contract with "must-not exit" units in constrained areas. Whether Option A, B, C or D would be most efficient depends on which, in practice, most closely reflects the TSOs' requirements after the auction, which is an empirical question.[30] Option E, however, makes use of information after the auction has cleared and allows the TSO to optimise the selection of plant to keep operational. It is therefore likely to produce the most efficient outcome compared to the other options in the Consultation Paper as all system constraints are taken into account. The RAs have suggested that the procurement of additional capacity under option B might be a problem for efficiency,[31] but this depends upon the volume of 'constrained –off' capacity which is not quantified, and does not consider the offsetting benefit of properly valuing constraints and thereby providing long term incentives for efficient management of, and investment in, the transmission system. Option B also promotes long term competition by minimising the impacts of structural market power under the auction mechanism, which will improve efficiency over the long term; an issue that is further exacerbated under options A, C and D, and option E if it constrains-off units, due to the fragmentation of the market caused by constraints. Our proposed hybrid option efficiently uses information from the auction to identify "must-not exit" plant, as in Option E, whilst retaining the potential long-term competition and efficiency benefits of Option B. Accordingly, we believe it should score as highly as any other option for efficiency, particularly if assessed on a long-term basis.[32]

Practicality – The hybrid option is at least as practical as Option E, which the RAs described as having "low implementation risk". The hybrid option is more practical than Options A or B because it does not require the constraints to be specified in advance of the auction. The hybrid option is more practical than options C or D because it does not require the development of (as yet undefined) heuristic rules or a solution algorithm for the first auction.

Security of Supply – Of the options considered by the SEM-Committee, Option B is the most highly rated according to security of supply criteria because the TSOs contract with additional units to meet locational constraints. Option E might merit the same rating for security of supply if it also results in the TSOs contracting with additional units – but the Consultation Paper does not clearly set out what steps the TSO would take after running the system security analysis. Leaving aside this issue, Option E is likely to result in higher security of supply than Option A to D, because it uses information about constraints after the auction has cleared, whilst the other options

[30] The SEM-Committee states that Option D is "likely to deliver the most efficient solution" (Consultation Paper, page 27). We disagree. The combinatorial optimisation will only deliver the most efficient solution *given the set of constraints that it has programmed in*. In practice, after the auction closes, it may become clear that the TSO needs to make adjustments to the solution selected by the combinatorial optimisation. In principle, the necessary adjustments could be larger with a combinatorial optimisation than using simpler approaches, such as the heuristic algorithm favoured by the SEM-Committee.

[31] Consultation Paper, paragraph 3.2.28.

[32] Energia acknowledge a potential issue in relation to the entry of new generation. However, we would observe that this issue can be dealt with via connection policy, which feeds into qualification for the CRM auction, and a robust "out of market" locational signals regime to create commercial incentives as discussed in section 1.3 of this response. Furthermore, it is unclear that options A to D are immune from this criticism as they rely on a simplified version of the transmission system and there is therefore no guarantee that their entry / exit signals will be any more efficient. Option E may fair better if it takes into account all system constraints and 'constrains-off' generation without compensation, but this would have other negative impacts as set out in more detail in section 1.3 above.

require the TSOs to specify constraints in advance of the auction. (We are not in fact convinced that this approach is sustainable without ex post interventions where necessary, which blurs the distinction between all the options.) The hybrid option secures additional units and includes an ex post assessment after the unconstrained auction is complete and therefore would score as highly or higher than Option E (subject to the approach taken to securing additional units) and above all other options for security of supply.

On the basis of this assessment we recommend that a hybrid of option B and E, as described above, is implemented by the SEMC.

1.7. Grid Code requirements

At para 2.2.10 of the Consultation paper, the RAs suggest that as a result of the current requirement in the Grid Code to give TSOs a 3 years' notice of an intention to close capacity, a generator unsuccessful at a transitional auction held in 2017 for capacity delivery in the years 2017/18 or 2018/19 would be prohibited from closing in those years. The RAs nevertheless recognise that "the failure to obtain missing money in a CRM auction could lead to insolvency and may leave some plant with insufficient revenues to operate".

We are of the firm view that the RAs may not reasonably or lawfully rely upon the existing three years' notice requirement when devising the CRM and have received legal advice from Arthur Cox to that effect. A Grid Code notice period of 3 years should not and cannot be relied upon for security of supply. The RAs appeared to suggest otherwise in I-SEM CRM Decision 2 (SEM-16-022) which states that: *"[t]here is a Grid Code requirement that plant give 3 years notice before closing – which means the [capacity] shortfall is unlikely to occur in those first three transition years"*(page 104). This is not an acceptable regulatory solution and in our view would be a difficult obligation to enforce from a legal and practical perspective. We welcome the fact that the Consultation Paper recognises that there is at least a question which arises as to "*the extent to which the Grid Code can be relied upon to manage exit of plant which does not win a reliability option".*

In this regard, we note that the three years' notice requirement in the Grid Code is entirely at odds with the objectives being pursued in the design of the capacity remuneration mechanism. In particular, one of the reasons advanced by the SEM Committee in support of its decision that the CRM will be a quantity-based mechanism is that it allows customers to benefit from competition between capacity providers "*as well as providing efficient exit signals".*[33] It is one of the assessment criteria list at para 1.3.2 of the Consultation Paper that the trading arrangements should incentivise appropriate investment and operation in the market and "*should not inhibit efficient entry or exit, all in a transparent and objective manner"* and para 1.2.5 describes the intention of the trading arrangements under I-SEM "*to deliver price signals to investors regarding entry and exit".* It was openly accepted by the regulatory authorities at the Senior Stakeholder Forum on 15 May 2015 that obligations placed on generators (through licence or Grid

[33] See SEM-14-085a, Integrated Single Electricity Market (I-SEM). SEM Committee Decision on High Level Design, p. 19.

Code) must allow exit in the same timeframe as signals given by the market[34]. The three years' notice requirement is impossible to reconcile with such a market design. With such a market design, there is no purpose for a requirement that generators, which ought to exit consistent with the CRM outcome, nevertheless must remain available for generation for a minimum of three years despite the fact that they should exit. We note that the RAs offer no justification for the three years' requirement and we are not aware of any particular reasons why the notice period is of three years. In GB, generators must only give six months' notice to close their plant and they are subject to less prescriptive bidding rules in the balancing market than is likely to be the case under I-SEM. In reality, generators will close plant in the event that fixed and variable costs are not recoverable along with a reasonable rate of return.

In such a context, it is not open to the RAs to take it as a given that a three years' notice requirement ought to apply as a default, particularly where there appears to be no justification for it, and none has been provided. Rather, it is a matter that is part of the issues that must be reviewed as part of the design of market rules that are best able to ensure that the capacity required will be available, by ensuring adequate and appropriate remuneration of wholesale electricity and of capacity.

We cannot see how the three years' requirement can be maintained with the proposed CRM. However, if the RAs are of the view that as a result of current licensing requirements existing plants must remain available for the next three years, then they must consider how to ensure that the capacity provided is adequately remunerated. Any other outcome could lead, as recognised by the RAs, to insolvency and/or leave some plant with insufficient revenues to operate. A set of rules producing such an outcome would clearly be entirely unfair and unreasonable and contrary to the RAs' statutory duties including the obligation to ensure that generators are in the position to finance the activities for which they are licensed and contrary to the constitutional protection of the right to property.

Accordingly, the three years' notice requirement in the Grid Code should be amended to align with commercial exit signals. The Grid Code should also be modified to include an option to withdraw such a notification, in order to allow flexibility for generators to respond to changing circumstances, for example, availability issues at other plant or interconnectors which have a material bearing on plant profitability.

1.8. Key recommendations

1. Taking into account the characteristics of the all-island market, we recommend that a hybrid of Option B and E be implemented to address locational issues as described herein and as supported with reference to the SEMC assessment criteria, including State aid considerations about which we would be happy to engage further with the RAs on procedural aspects.
2. Any decision not to compensate "constrained-off" generators would be seen as regulatory opportunism and would have a detrimental effect on

[34] See EAI letter to SEM Committee of 28 May 2015.

investor confidence in this market. It may also be susceptible to legal challenge. Furthermore and in any event, this is a false economy based on short term opportunism that is clearly not in the long term interest of consumers. It will remove fundamental market signals that provide both useful information for regulation and the basis for incentives on the TSO to efficiently manage and invest in the transmission system and would increase the cost of capital for investment in generation. For the reasons outlined in this response Energia recommends that capacity auctions are unconstrained and therefore the concept of being 'constrained-off' should not apply.

3. A key consideration for pursuing the preferred options C or D would seem to be a desire to show, for the purpose of State aid clearance, that all decisions relating to the allocation of capacity remuneration are taken on the basis of a single, competitive auction. However, we have been advised by Arthur Cox that this is not in fact required under the State aid rules, or indeed in this case, compatible with the most efficient outcome, and therefore State aid rules, as a desire will not be fulfilled, since the proposed options recognise only a limited set of system constraints. Accordingly, the TSO would in any case have to assess the adequacy of the system and enter into ex post negotiations with generating units required for feasible and secure operation of the system that did not clear the CRM auction.

4. As a more general point, we have serious concerns that the State aid rules are being relied upon in the Consultation Paper without a full consistency and compliance analysis having been undertaken. A very concrete assessment is required which takes into account the characteristics of the system in its entirety, including in the case of the all-island electricity market, the fact that it is a highly constrained but relatively small market displaying dominance issues and with a high penetration of renewables. Energia is concerned that this exercise has not been carried out in full. In particular, it is not clear that sufficient attention has been given to the reasons for the locational issues arising and whether, from a very practical perspective, it is in fact possible to address, and rectify, them by way of the CRM in a manner that is consistent with the requirement of the State aid Guidelines. This fundamental shortcoming must be addressed.

5. We are of the firm view that the RAs may not reasonably or lawfully rely upon the existing three years' notice requirement when devising the CRM and have received legal advice from Arthur Cox to that effect. It therefore cannot be relied upon to ensure security of supply. Accordingly, the current Grid Code requirement to give 3-years notice of plant closure should be modified to align with commercial exit signals under I-SEM, including an option to withdraw such a notification.

6. We recommend that the NERA Memo will considered in detail and the concerns raised therein be addressed.

7. Finally, with respect to market power, we recommend that further careful consideration is given to ESB's structural market power under the I-SEM and DS3 market designs. The design of local market power controls must also be carefully considered to ensure the adequate remuneration of

generators required for reasons of system security to prevent further undermining security of supply. We also trust the NERA Memo is instructive in this regard.

We ask that the SEM Committee gives serious consideration to this response and the analyses developed by our expert third party advisors before concluding this matter. We are available to meet and discuss this response at the earliest opportunity and look forward to hearing from you.

2. List of Consultation Questions

Below we set out our response to the questions in the Consultation which should be read in conjunction with the NERA Memo.

Section 2 – Issues and Proposals

2.5.5 This paper focuses on issues relating to implementing this proposed solution. However, views are also invited from interested parties, with respect to any other options that could or should be considered to address local capacity issues.

Energia advocates a hybrid of options B and E whereby CRM auctions are run on an unconstrained basis, the TSO then conducts an ex-post full system security assessment to identify any additional units not selected via the CRM but required for reasons of system security;[35] finally that the TSO conduct a bilateral contracting process to secure the continued operation of those units. For the avoidance of doubt, similar to Option B the continued operation of any additional units secured via bilateral contracts under this hybrid option would not result in de-selection of other 'in merit' capacity.

More details on this hybrid option, including its benefits relative to the proposed options, are provided in our answers to questions 3.6.1 below.

We are of the firm view that the RAs may not reasonably or lawfully rely upon the existing three years' notice requirement when devising the CRM and have received legal advice from Arthur Cox to that effect. It therefore cannot be relied upon to ensure security of supply. Accordingly, the current Grid Code requirement to give 3-years notice of plant closure should be modified to align with commercial exit signals under I-SEM, including an option to withdraw such a notification. See section 1.7 for more details.

2.6.1 Do you agree with the assessment of the potential for exit and lack of new entry during the transition period set out in this section, and do you think that the potential for exit creates a security of supply issue given locational constraints?

Energia notes the concern stated by the TSOs in the "I-SEM Capacity Remuneration Mechanism: Proposed Methodology for the Calculation of the Capacity Requirement and De-rating Factors" paper that "a CRM auction result that satisfies the de-rated capacity requirement will not necessarily allow the TSOs to operate the power system within its operational limits while still satisfying the LOLE standard".[36] Furthermore the TSOs in that paper caution that "the loss of load expectation could be higher than predicted if the theoretical available capacity from a portfolio of generators cannot be

[35] For the avoidance of doubt a full system security assessment by the TSO should include all constraints on the power system including any arising due to locational requirements for the provision of system services. This is how reference to a full system security assessment should be understood throughout this response.
[36] I-SEM Capacity Remuneration Mechanism: Proposed Methodology for the Calculation of the Capacity Requirements and De-Rating Factors P.36

delivered due to transmission or security limitations"[37] – i.e. that the LOLE in practice may be greater than the security standard due to the impact of system constraints. We also note that the TSOs do not put a time limit on this issue – i.e. they do not view it as just a transitional issue but a more general, practical concern regarding the fact that the assumptions made in the processes and methodologies supporting the CRM design do not match the underlying physical realities of operating the power system. This is not necessarily a criticism of the CRM design per se but rather a result of the simplifying assumptions that usually have to be made in market based mechanisms. The issue in the specific case of the I-SEM, however, is that the negative impact of these simplifying assumptions on system management is made more acute due to the small size of the market combined with the high number of system constraints – a fact recognised in the current SEM market design[38] and that is well documented and acknowledged in relation to the all-island market.

"The TSOs agree that further consideration should be given to the management of locational issues, both with respect to longer term operation of the CRM and during the transitional period".[39]

Energia also notes that the Locational Issues paper indicates that a large reduction in installed capacity may be incentivised under the I-SEM CRM – estimated at c2.6 GW, or the equivalent of c6 CCGTs. While a sloping demand curve may reduce the level of exit, if the indicated figures are accurate it seems likely that a number of generating units will exit the market. Our concern is not the likely exit of generation as such, but rather that the appropriate generation is selected for exit. We have raised concerns regarding the risk of inappropriate exit numerous times in previous consultation responses. These concerns are, inter alia, a result of the following factors:

1. ***Competition:*** The design of the CRM itself confers significant benefit on ESB allowing them to diversify risk across their large, diverse generation portfolio. This could result in a significant reduction in the risk premium associated with less reliable generation assets in their portfolio, allowing such units to displace more reliable generation assets owned by competitors. ESB will also have a significant information advantage relative to their competitors when participating in the capacity auction on account of their large portfolio of generators. Given the state ownership of ESB there is also the risk that offer submissions to the CRM auction made by ESB will be influenced by non-commercial considerations[40] - e.g. set below costs to keep uneconomic units open to avoid industrial action. The

[37] I-SEM Capacity Remuneration Mechanism: Proposed Methodology for the Calculation of the Capacity Requirements and De-Rating Factors P.36

[38] For example, the combination of an early gate closure, the ex-post nature of the energy market and the existence of a constraint payments mechanism which provides extensive centralised control to the TSO.

[39] I-SEM Capacity Remuneration Mechanism: Proposed Methodology for the Calculation of the Capacity Requirements and De-Rating Factors P.36

[40] Auctions for DS3 (as propped in the DS3 HLD) would be prone to the similar issues and would further magnify competition problems in the capacity market.

potential distortion of the capacity market that may result from these concerns could further increase the risk of inappropriate exit and thereby cause a downward cycle of reducing competition.

2. ***System Security:*** The fact that market mechanisms do not accurately reflect the physical realities of operating the power system. This issue has been made more acute due to the measures proposed for mitigation of local market power that threaten the revenue adequacy of “constrained-on” generators. Energia has always advocated the need for a mechanism to facilitate bilateral contracting by the TSO to ensure delivery of a secure power system and we welcome the recognition of system security concerns in relation to the CRM design in the current consultation paper. For the reasons outlined in this response, however, the preferred solutions (i.e. Options C and D) are not the best ways to address these concerns.

If inappropriate exit does occur, Energia observes that this will mostly likely cause system security problems. These issues will be particularly acute in the transitional timeframe, as there will be insufficient time to secure new entry, but as the TSO point out, they are not merely transitory concerns. For the reasons outlined in our answer to question 2.6.3 below it is naïve for the SEMC to rely on excessive notice times to keep plant available under the grid code to mitigate this risk, as the costs to a participant of not acting upon an exit signal could be prohibitive and therefore such units are likely to have to close.[41]

Therefore, on the basis of the above, and our own knowledge of the highly constrained nature of the system, Energia agrees that there is a substantial risk of exit in the transitional period and that this exit is unlikely to be offset by new entry. Furthermore, that this exit could be inappropriate due to competition and system security concerns, and that it could therefore lead to serious security of supply issues given the underlying physical realities of the power system. Finally, we would agree with the TSO’s view that security of supply concerns, which arise out of the simplifying assumptions that are required by market mechanisms, are not merely transitional, but are enduring features of the CRM design and therefore require robust, long-term solutions – i.e. contracting solutions that ensure the delivery of a stable and secure power system.

2.6.2 Do you agree that locational constraints should be incorporated in the CRM? Please elaborate your rationale in your response.

Energia observes that any modelling of locational constraints directly in the CRM auction will only represent what is likely to be a very limited subset of the overall constraints on the physical power system. It will, however, add significant complexity to the auction clearing processes, and potentially to the pricing mechanism, without producing a secure and feasible solution and therefore removing the need for further ex-post adjustments. The question

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[41] Any plant that fails to cover its operating costs is in imminent danger of insolvency. Even if the owners are prepared to bear losses for some time, the firm’s creditworthiness will suffer and fuel suppliers may no longer be willing to sell it fuel. The plant’s exit may therefore be precipitated by actions outside the control of those bound by the Grid Code.

that therefore needs to be properly addressed is whether the addition of this complexity is worth the reduction in transparency, and the design and delivery risks that it creates.

The proposed approach, presented at a very high-level in the consultation paper, is to only model a simplified subset of the capacity delivery constraints and to ignore constraints resulting from locational requirements for provision of ancillary services. Such a piecemeal approach to constraint modelling in the CRM, however, may actually result in less efficient plant selection compared to our suggested alternative approach of a hybrid of options B and E where auctions are carried out on an unconstrained basis, the TSOs run a full system security assessment to determine any additional units not cleared via the capacity auction required to securely operate the power system, and a bilateral contracting process is run by the TSOs to secure the continued operation of any such units. For the avoidance of doubt, similar to Option B the continued operation of any additional units secured via bilateral contracts under this hybrid option would not result in de-selection of other 'in merit' capacity.

This approach has the potential advantage of facilitating a detailed assessment of the security of the power system closer to the delivery period in question[42] and therefore not only reduces the risk of inefficient plant selection due to adopting a piecemeal approach to the modelling of physical system constraints.

The only reason not to adopt this approach and to pursue the preferred options C and D would seem to be a desire to show, for the purpose of State aid clearance, that all decisions relating to the allocation of capacity remuneration are taken on the basis of a single, competitive auction. However, this is a futile objective, since options C and D model only a small subset of the actual physical constraints on the system,[43] and therefore the TSOs, even under these options, will have to assess the adequacy of the system and enter into ex post negotiations with any units required by the system but not cleared in the CRM auction.[44] The desire to rely on a single, competitive auction therefore does not provide a compelling reason for the selection of options C and D over any other options because the additional complexity it creates for the auction process does not remove the need for bilateral contracting by the TSOs.

We note also that options C and D provide the opportunity not to compensate constrained off generators. As set out in our answer to question 3.6.3 below, however, this is a false economy that is not in the long term interest of consumers. It will remove fundamental market signals that provide both

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[42] This would not preclude a system assessment being carried out after a T-4 auction to allow the TSO the option to contract with a generator that they know is behind an enduring system constraint to mitigate long standing system security concerns. Such a pragmatic approach would relieve pressure on the TSO compared to leaving everything to after a T-1 auction, while entering into longer term contracts may reduce costs and improve efficiency by removing uncertainty for both the TSOs and generators.

[43] Paragraph 2.4.2, key principles (1) and (2).

[44] Energia would note that this problem will not be addressed by passing it over to the DS3 auction process, because the exact same issues will arise.

useful information for regulation and the basis for incentives on the TSO to efficiently manage and invest in the transmission system.

These issues are discussed in detail in sections 4.2 of the NERA Memo accompanying this response.

2.6.3 Feedback in relation to the specific Grid Code requirements are sought in respect of the following:

- **The extent to which the Grid Code requirements can be relied upon to manage exit of plant which does not obtain a Reliability Option;**
- **Whether it is appropriate to provide assurances that generators which do not obtain a Reliability Option in the transitional auctions (which happen on a T-1 basis) be released from their obligations to give 3 years notice in accordance with the Grid Code; and**
- **Whether the Grid Code requirement should be extended from 3 years notice, to say 3 years 6 months to align with T-4 auction timings.**

We are of the firm view that the RAs may not reasonably or lawfully rely upon the existing three years' notice requirement when devising the CRM and have received legal advice from Arthur Cox to that effect. It therefore cannot be relied upon to ensure security of supply. Accordingly, the current Grid Code requirement to give 3-years notice of plant closure should be modified to align with commercial exit signals under I-SEM, including an option to withdraw such a notification. See section 1.7 for more details.

2.6.4 Do you agree with the key principles proposed for any locational capacity framework within the CRM?

Energia's assessment of the key principles outlined in paragraph 2.4.2 of the consultation paper is provided below.

Principle 1: *Only local capacity deliverability constraints would be modelled*

Energia questions whether it is sensible to identify a subset of constraints caused only by limits on "local capacity deliverability" (LCD), separate from the wider set of constraints that culminate in the actual "system security" concerns. Since "system security" is primarily driven by the requirement for delivery of services or products in specific locations, it is not clear what LCD constraints actually are or how they differ from other constraints arising from other issues that require generation capacity to be situated in certain areas. It seems to rule out the modelling of thermal constraints, n-1 risks and voltage constraints, as well as any other constraints driven by local requirements for system services. The objective basis for restricting the type of constraints included under the concept of LCD constraints however is unclear and no evidence is provided to give confidence that the resulting outcome from modelling only such constraints is useful in delivering a secure system, or efficient in addressing the actual system security concerns? Energia's primary concern therefore is that focusing on a restricted type of system constraint is likely to produce infeasible, insecure outcomes that are potentially inefficient. This is discussed further in our comments on principle 2 below.

Principle 2: *Locational deliverability constraints will only be included where the need is obvious and clear*

This principle further exacerbates the problems identified in relation to principle 1 and increases the risk of inefficient selection. To the extent that a simplified limited subset of the power system constraints are modelled in options A to D the TSOs will need to perform a detailed security analysis such as envisaged in option E, and there is therefore an increased risk that the final selection of plant to manage system constraints will be sub-optimal. For example, two units may end up being selected where one single plant may have been able to manage all relevant constraints when looked at in a holistic manner. This is because the unit selected via the CRM auction to meet LCD constraints may not meet other power system constraints resulting in the need to procure services from a further unit, whereas if the appropriate unit had been selected in the first place (via the TSOs security analysis) it could have met all relevant constraint requirements in a given area.

Application of the principle also diminishes the transparency and predictability of the auction process, since there seems to be no objective definition of an "obvious and clear" constraint. As explained above, this limited approach may not even select the generators best placed to alleviate these constraints, once the other omitted system security constraints are taken into account. No evidence is presented in the consultation paper to confirm that a constrained auction process as envisaged under options C and D will select generation capacity on a more efficient basis than an unconstrained auction. Furthermore, to the extent that constrained off capacity is not compensated in the CRM, application of this principle further increases the risk of inappropriate exit. As such it could result in capacity that may be required in the future (e.g. if constraints change) exiting the market; a situation that could easily arise within a small, highly constrained market such as the I-SEM. The spurious accuracy of a semi-constrained auction based on selective and partial modelling of system constraints could therefore put future security at risk unless there was some further process to ensure security of supply.

The underlying assumption behind the principle is that the identification of system constraints required to be modelled in the CRM is self-evident, but this may not be the case. Inclusion of the additional constraints (such as those that would be applied in a full TSO security check) could lead to different plant selection than that derived from selectively modelling 'major' LCD constraints due to the interacting dynamics of the power system. Detailed analysis would therefore need to be carried out to identify the minimum number of critical constraints required to be modelled such that the outcomes from the CRM selection process would closely match the outcomes of a TSO security analysis. No such analysis seems to have been completed, and therefore the assumption that some constraints are "obvious and clear" is unwarranted and the principle flawed.

A more appropriate principle than principles 1 and 2 might be: "The minimum number of constraints should be modelled to ensure that the CRM outcome approximates the outcome of a detailed TSO security analysis" for the reasons outlined above and in our answer to question 2.6.2. However, to preserve any objectivity or transparency, this approach would require extensive modelling prior to any auction, and detailed review of the TSOs' conclusions regarding the system constraints that should be modelled via the CRM auction to determine how well they would "approximate" a more detailed security analysis. Adopting such a principle however is likely to make option C and D more difficult to implement and would require prolonged regulatory scrutiny and public consultation. Recognition of these difficulties would rather lend support to a hybrid version of options B and E (using an unconstrained auction with ex post negotiations) as outlined in our answer to question 3.6.1 below.

Principle 3: *Identification and quantification of local capacity deliverability constraints should be as simple and transparent as possible*

Energia supports this principle but observes that there are no grounds for restricting it to local capacity deliverability constraints. Rather it should encompass all constraints, including any modelled by the TSO via an ex-post security analysis. The nature of the constraints will ultimately determine the simplicity of the modelling approach that is feasible but it is important to ensure that the methodology chosen does not unnecessarily convolute the process required.

Transparency can be achieved by providing detailed descriptions of all relevant processes and their associated input and output data, and by ensuring appropriate governance and oversight arrangements are put in place. The Ten-Year Transmission Forecast Statement would provide the best starting point for such discussions.

We would observe that this principle is consistent with any of the options advocated in the paper, including the hybrid version of options B and E we recommend.

2.6.5 Do stakeholders agree that clear and large existing capacity delivery constraints should be reflected within the CRM auction, for example limiting this to the North-South constraint and the Dublin area constraint?

Please see our answer to question 2.6.2 and 2.6.4 above. To the extent that a simplified limited subset of the power system constraints are modelled in options A to D, the TSO will need to perform a detailed security analysis such as envisaged under option E anyway. Furthermore, adopting a piecemeal approach to system constraint modelling in the CRM, and ignoring locational constraints associated with the delivery of ancillary services, is likely to result in the sub-optimal selection of plant required for system security. Little purpose, if any, is therefore served by modelling such a limited range of constraints, since the resulting outcome of the CRM auction would likely be infeasible, insecure and inefficient.[45]

While some short-term savings may be achieved if a CRM auction with limited constraints excludes some in-merit ("constrained-off") generation without compensation, such savings would result in a false economy. Some of the plant initially constrained off may have to be constrained on again once a full

[45] Could result in the incorrect units being 'constrained-on' and 'constrained-off' via the auction due to an incomplete assessment of system security requirements.

system security check is completed by the TSO, whilst the lack of compensation removes a valuable market signal for regulators and the TSOs regarding the true cost of constraints. In particular, over the long-term, this approach would have a negative impact on the incentives of the TSOs, and therefore the ability of the regulators, to efficiently manage and invest in the transmission system.

These issues are discussed in more detail in our answer to question 3.6.3 below.

2.6.6 Do stakeholders agree with the high level proposed solution for dealing with locational capacity issues?

No. Energia is concerned that piecemeal modelling of constraints via the CRM auction process adds unnecessary complexity to the auction clearing process, while not ensuring delivery of a feasible, secure or efficient outcome. This is because the constraints modelled via the auction mechanism will only be a small subset of the actual physical constraints active on the power system. Furthermore, in crudely selecting “out of merit” generation the auction clearing mechanism will be - equally crudely - de-selecting “in merit” generation, without proper consideration of the impacts on wider constraint management. Leaving aside the fact that not compensating such units for being constrained off in the capacity market will create extremely unhappy losers, to the extent that the selection of “out of merit” generation was not done with full reference to the actual constraints of the physical power system, the de-selection process may arbitrarily result in units needed for reasons of system security not being cleared in the auction. This increased risk of inappropriate exit would then need to be sorted out via some form of security analysis conducted by the TSOs (as envisaged in Option E) combined with a bilateral contracting process between required generators and the TSOs. Therefore adding piecemeal constraints into the CRM auction adds considerably to its complexity without necessarily resulting in a commensurate increase in its efficiency.

Energia therefore advocates a hybrid of options B and E whereby CRM auctions are run on an unconstrained basis, the TSO then conduct an ex-post full system security assessment to identify any additional units not selected via the CRM but required for reasons of system security; finally that the TSO conduct a bilateral contracting process to secure the continued operation of those units. For the avoidance of doubt, similar to Option B the continued operation of any additional units secured via bilateral contracts under this hybrid option would not result in de-selection of other ‘in merit’ capacity.

More details on this hybrid option, including its benefits relative to the proposed options, are provided in our answers to questions 3.6.1 below.

2.6.7 If you do not agree with or have further view any of the proposals or assessment set out in this section, please outline why and where relevant suggest alternatives.

Energia does not support piecemeal modelling of constraints via the CRM auction process on the grounds that such an approach adds unnecessary complexity to the auction clearing process, while not ensuring delivery of a feasible, secure or efficient outcome; rather it could make the solution worse.

We recommend that our proposed hybrid of options B and E is therefore implemented instead.

More details on this hybrid option, including its benefits relative to the options presented in the Consultation Paper, are provided in our answers to questions 3.6.1 below.

Section 3 – Approaches to Dealing with Locational Constraints

3.6.1 Which option do you prefer for the Auction Design Framework and why?

The options put forward in the consultation paper are described at a very high level and do not provide sufficient information to allow a proper assessment. For example, in options A and B it is unclear what constraints will be modelled, while in option C no details are provided in relation to the heuristic rules that will be used. Option D does not provide details of the problem that will be presented to the MIP solver, or how it will be solved, while it is unclear from the description of option E whether the intention is to procure additional capacity to secure the system over and above that procured via the capacity auction, or 'constrain-off' capacity in surplus areas to offset 'constrained-on' capacity in deficit areas. If it is the latter no details are provided as to how this would be done in practice.

The assessment put forward in the paper also proceeds on the basis of a number of assumptions. For example, the assessment of the efficiency of options C and D are based upon the following unverified suppositions:

1) the outcome of the heuristic / algorithm will approximate the outcomes of the full TSO security analysis; and
2) An unconstrained auction result will require significant additional contracting outside the CRM to secure the system.

Neither of these assumptions seems to have been tested. The outcomes from modelling a small subset of the physical system constraints on the system may bear little resemblance to the outcomes required by the TSOs to ensure secure operation of the power system and it is by no means "obvious and clear" exactly which constraints should be included. Therefore, as set out in our answer to question 2.6.4 above, careful detailed analysis would need to be completed to determine the minimum number of system constraints required to be modelled to approximate the outcomes of the TSO system security analysis. No evidence of such analysis is presented in the consultation paper, despite the commercial consequences any resulting inappropriate exit signals from the CRM would have for both generators and the TSOs.

Given the proposal to model only a small subset of the physical constraints on the system the auction clearing mechanism under option C or D could result in generation required for wider system security reasons actually being de-selected by the heuristic or algorithm. As options A and B also model a subset of the physical constraints on the system, option A could remove a sub optimal set of units from the auction process, while option B could result in sub-optimal additional contracting of units by the TSO.[46] These issues are not properly considered in the assessment of options A, B, C and D but they could have a material impact on their overall efficiency relative to the more straightforward approach we have put forward – i.e. the hybrid of options B and E.

The Consultation Paper relies on assumptions regarding the potentially detrimental effect of options B and E on competition. However, it is not clear how these options fare any worse by this criterion than options C and D, particularly if objective assessment criteria are defined for the checks carried out under options B and E. Options B and E (and possibly C) proceed with an unconstrained auction result that is then adjusted to reflect constraints. In option D the modelling of these constraints is fully integrated into the auction clearing and pricing mechanism. We note however the potential for unhappy losers, results that are difficult to understand and unintuitive pricing outcomes (because constraints affect pricing) under options C and D, which would have a negative impact on competition.

Furthermore, the auction outcome in options A, C and D will be materially segmented by constraints, effectively fragmenting the market, and reducing the potential for competition. Under option B the auction process is simplified in comparison, the market is larger (potentially increasing the scope for competition) and the results are more intuitive (because the security check is auxiliary to the clearing process and does not impact upon the results). Providing option E does not result in the de-selection of auction winners, as is the case in our proposed hybrid of options B and E, it would fare as well as option B in its assessment against the competition criteria. It is therefore not clear why option B, or for that matter the hybrid option of B and E we recommend, would fare any worse from a competition point of view than options C and D, indeed they should rather score higher than those options. They also score higher when assessed against the practicality criteria as they are significantly easier to deliver, given the auction design is simplified considerably.

In relation to State Aid (the Internal Market criteria as outlined in the consultation paper) we would agree that Option A scores poorly against this criterion given capacity contracts are awarded prior to the auction process, however it is unclear why option B, or our recommended hybrid of options B and E, would fare worse than options C and D in the assessment against this criterion if the additional contracting of units is required for reasons of system security. We note in this respect that the use of bilateral contracts, envisaged by the RAs at para 2.4.5 should not involve State aid and will therefore not be subject to prior clearance. This is because the procurement of system services would not involve the State, or the use of State resources, but rather the exercise by the TSOs of their commercial functions and financial resources, in a normal, albeit likely regulated, way. (This being the case does not of course prevent notification to the European Commission of the approach to be used for the purpose of dealing with locational constraints,

[46] In practice, we assume the TSO would run a full system security analysis similar to that envisaged under option E to ensure contracts were struck with the appropriate generators.

including for the purpose of confirming that there is no State aid involved. We would be happy to engage further with the RAs on procedural aspects.)

Under options C and D, and option E if some capacity is “constrained off” to offset “constrained on” capacity, system constraints would be driving the selection process for capacity contracts, limiting competition compared to the more competitive unconstrained capacity auction under option B and our proposed hybrid of options B and E. We note that incorporating constraints into the CRM auction, or using constraints to change the outcome of an unconstrained auction (the reallocation of capacity contracts), produces a different outcome from securing additional units for reasons of system security. It is also different from implementing capacity zones to deal with constraints, a solution that is impractical for the I-SEM as set out in detail in section 1.1 of this response.

In the case of I-SEM the small size of the capacity market relative to the large size of capacity units, combined with the high number of constraints on the power system, when considered in the context of the dominance of ESB, means that further fragmentation of the market would result in capacity zones that were too highly concentrated to support a competitive auction-based selection process. The European Commission seems to acknowledge these potential issues and has stated that the use of a competitive allocation process will not always guarantee competition, in which case an alternative process is justified:

“When market power exists and it is not possible to extend participation in the mechanisms –due for instance to the poor development of the electricity network or of demand response– an administrative allocation process can be justified with a view to minimise the costs of the system.”[47]

A more detailed and rigorous assessment of the options is provided in section 2 of the NERA memo accompanying this response. As NERA point out in their memo options C (and by inference option D) are rated more favourably by the SEMC assessment because they are vaguely defined and there has not been a rigorous, objective attempt to identify the potential drawbacks associated with them. As they observe:

“… relying on the difference in depth of explanation of different options (in other words, their relative vagueness) is not a sound basis for decision-making. There are certainly no ground for favouring Option C just because all the other options seem to face known problems whilst Option C is so poorly specified that its problems are unknown. Unfortunately, that seems to be the sole basis of the RAs’ preliminary view (as set out paragraph 3.2.49).”[48] P.4

Given the issues we have identified with each of the options A to E Energia recommends an alternative approach, which is a hybrid of options B and E. Under this hybrid approach CRM auctions would be run on an unconstrained basis, the TSO would then conduct an ex-post full system security assessment to identify any additional units not selected via the CRM but

[47] European Commission Staff Working Document accompanying the Interim Report of the Sector Inquiry on Capacity Mechanisms {C(2016)2107 final}, para 5.3.4.2
[48] NERA Memo, section 2.1.

required for reasons of system security; finally the TSO would conduct a bilateral contracting process to secure the continued operation of those units. For the avoidance of doubt, similar to Option B the continued operation of any additional units secured via bilateral contracts under this hybrid option would not result in de-selection of other ‘in merit’ capacity.

This hybrid option would score at least as well as, if not better than, the SEM-Committee’s proposed list of options and would replace Options C and D as the preferred interim and enduring option. An assessment of this hybrid option against the criteria set out in the Consultation Paper is provided at the end of this answer.

Under our recommended hybrid option the TSOs would need to carry out a full security assessment after each T-1 auction (including the transitional T-1 auctions). This would not, however, preclude a similar assessment being carried out after T-4 auctions. The TSOs should retain an option to contract on a longer term basis to mitigate long standing system security concerns. Such a pragmatic approach would relieve pressure on the TSOs compared to limiting the assessment and contracting process to after a T-1 auction, while entering into longer term contracts in appropriate circumstances may reduce costs and improve efficiency by removing uncertainty for both the TSOs and generators. Furthermore, the timing of T-1 auctions would need to provide sufficient time to allow the orderly exit of generation that receive an exit signal from the CRM and are not required for system security reasons. This would require a revision of the notice times for closure required under the Grid Code. We note that a revision to these timings is necessary anyway to align Grid Code obligations with commercial exit signals as set out in our answer to question 2.6.3 above, and discussed further in section 1.7.

In relation to the indicative timelines that would be required under this approach we would estimate the time required for orderly exit of generation to be c12months, which would therefore require up to an c18 month lead time ahead of delivery for a T-1 auction, depending upon the timeline required by the TSO to complete their final security analysis. This provides a period of c6 months, which should be sufficient for the generator to complete any required contracting process with the TSO, particularly if contracting for some longer standing security issues has already taken place. The detailed timings however would require further consideration and consultation and our views in this area may be subject to change.

We can appreciate the desire to align the form of contracts issued to “must-not exit” plant with reliability options but we would note that it is not essential and, in fact, may not be appropriate. Triggers for provision of services from “must not exit” plant are likely to be different. Therefore, another form of contract specifically tailored to the specific service required may be more appropriate, providing their terms are reasonable and do not impose excessive, difficult to manage, commercial risks[49]. We would also stress that for contracts to be effective in delivering system security the terms would need to ensure the recovery of fixed costs plus a reasonable rate of return, so that

[49] Such risks would undermine revenue adequacy and therefore the continued operation of the generator.

the contracted generator can remain open. [50] The final form of contracts however would require further consideration and consultation and our views in this area may be subject to change.

A detailed assessment of our recommended hybrid of option B and E against the SEM-Committee's criteria is provided below:

Internal Market: The hybrid option consists of an unconstrained competitive auction. This auction awards contracts to the cheapest available sources. Separately, following the auction results and only in cases where there is a demonstrated need to keep specific units operational, the TSOs would engage in bilateral contracting. In all the options A-E, the TSOs are likely to need to sign bilateral agreements with plants which do not succeed in the auction but are required for system security – i.e. "must-not exit" units. This need arises because of the removal of constraints from, or the simplification of the constraints included in, the auction or the algorithm. As in these cases, the hybrid option will only require the TSO to procure bilateral contracts with units that are necessary for system operation in the light of all of the information provided by the auction. It is therefore unclear why our recommended hybrid option would score lower against this criterion than the preferred options C and D, which fragment the capacity market on the basis of a set of simplified constraints that are unlikely to deliver a secure mix of generation.

Transparency: As described in the NERA Memo in section 2.2.2, all the options A-E suffer from a certain lack of transparency, because the TSO must take action after the auction to secure the operation of "must-not exit" units. Options C and D entail an additional lack of transparency *before* the auction, because of the hidden TSO interventions behind the design of "heuristic" rules or constraints in the MIP solver and how these may impact upon auction outcomes. Potential transparency issues with our hybrid option could be greatly reduced simply by forcing the TSOs to publish details of the security analysis they will conduct prior to their selection of "must-not exit" units. Whereas the perceived benefits attributed to options A and B based upon their transparency require the simplification of the constraints applied undermining the efficiency of these options. Regardless, it is unclear why our recommended hybrid option would score lower against this criterion than the preferred options C and D.

Efficiency criterion: – The outcomes of options A, B, C and D all rely on simplified assumptions made prior to the auction, about the location and likely level of constraints on the system. As a result they may over-procure capacity in some locations and may still require the TSOs to contract with "must-not exit" units in constrained areas. Whether Option A, B, C or D would be most efficient depends on which, in practice, most closely reflects the TSOs' requirements after the auction, which is an empirical question.[51] Option E,

[50] Any plant that fails to cover all its costs (including its costs of financing) is in imminent danger of insolvency. Even if the owners are prepared to bear losses for some time, the firm's creditworthiness will suffer and fuel suppliers may no longer be willing to sell it fuel. The plant's exit may therefore be precipitated by actions outside the control of those bound by the Grid Code.

[51] The SEM-Committee states that Option D is "likely to deliver the most efficient solution" (Consultation Paper, page 27). We disagree. The combinatorial optimisation will only deliver the most efficient solution *given the set of constraints that it has programmed in*. In practice, after the auction

however, makes use of information after the auction has cleared and allows the TSO to optimise the selection of plant to keep operational. It is therefore likely to produce the most efficient outcome compared to the other options in the Consultation Paper as all system constraints are taken into account. The RAs have suggested that the procurement of additional capacity under option B might be a problem for efficiency,[52] but this depends upon the volume of ‘constrained –off’ capacity which is not quantified, and does not consider the offsetting benefit of properly valuing constraints and thereby providing long term incentives for efficient management of, and investment in, the transmission system. Option B also promotes long term competition by minimising the impacts of structural market power under the auction mechanism, which will improve efficiency over the long term; an issue that is further exacerbated under options A, C and D, and option E if it constrains-off units, due to the fragmentation of the market caused by constraints. Our proposed hybrid option efficiently uses information from the auction to identify “must-not exit” plant, as in Option E, whilst retaining the potential long-term competition and efficiency benefits of Option B. Accordingly, we believe it should score as highly as any other option for efficiency, particularly if assessed on a long-term basis.[53]

Practicality – The hybrid option is at least as practical as Option E, which the RAs described as having “low implementation risk”. The hybrid option is more practical than Options A or B because it does not require the constraints to be specified in advance of the auction. The hybrid option is more practical than options C or D because it does not require the development of (as yet undefined) heuristic rules or a solution algorithm for the first auction.

Security of Supply – Of the options considered by the SEM-Committee, Option B is the most highly rated according to security of supply criteria because the TSOs contract with additional units to meet locational constraints. Option E might merit the same rating for security of supply if it also results in the TSOs contracting with additional units – but the Consultation Paper does not clearly set out what steps the TSO would take after running the system security analysis. Leaving aside this issue, Option E is likely to result in higher security of supply than Option A to D, because it uses information about constraints after the auction has cleared, whilst the other options require the TSOs to specify constraints in advance of the auction. (We are not in fact convinced that this approach is sustainable without ex post interventions where necessary, which blurs the distinction between all the

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closes, it may become clear that the TSO needs to make adjustments to the solution selected by the combinatorial optimisation. In principle, the necessary adjustments could be larger with a combinatorial optimisation than using simpler approaches, such as the heuristic algorithm favoured by the SEM-Committee.

[52] Consultation Paper, paragraph 3.2.28.

[53] Energia acknowledge a potential issue in relation to the entry of new generation. However, we would observe that this issue can be dealt with via connection policy, which feeds into qualification for the CRM auction, and a robust “out of market” locational signals regime to create commercial incentives as discussed in section 1.3 of this response. Furthermore, it is unclear that options A to D are immune from this criticism as they rely on a simplified version of the transmission system and there is therefore no guarantee that their entry / exit signals will be any more efficient. Option E may fair better if it takes into account all system constraints and ‘constrains-off’ generation without compensation, but this would have other negative impacts as set out in more detail in section 1.3 above.

options.) The hybrid option secures additional units and includes an ex post assessment after the unconstrained auction is complete and therefore would score as highly or higher than Option E (subject to the approach taken to securing additional units) and above all other options for security of supply.

On the basis of the assessment above we therefore recommend that a hybrid of option B and E, as described above, is implemented by the SEMC.

3.6.2 Should the capacity price be set equal to: a) the highest-priced bid accepted in the unconstrained merit order; or b) the highest-priced bid which is both: accepted in the unconstrained merit order; and selected as a winning bid after lumpiness and locational considerations have been resolved?

The capacity price should be set equal to the highest bid accepted in the unconstrained merit order (i.e. option 1 in the Consultation Paper). As the SEM-Committee states, the capacity price from an unconstrained merit order is "likely to be a better approximation of the long run marginal cost of capacity (if bidders bid truthfully), and therefore a *more efficient investment price signal*."[54] [emphasis added] The other options considered have the effect of depressing auction prices below this level, by selecting lower priced bids, without justification. Option 1 will therefore result in a more efficient outcome over the long term.

As NERA explains in the accompanying memorandum, option 2 introduces a systematic downward bias to clearing prices below the competitive level.[55] Pursuing short term reductions in market prices is not consistent with any criterion used by the SEM-Committee in selecting between options, and nor should it ever be adopted as an additional criterion. Trying to reduce prices below the competitive level in any market might seem to offer short-term reductions in consumer bills, but it will force bidders to compensate by adapting their bid prices and/or the type of plant they offer. The resulting inefficiency and increased risks for investors will increase customer bills in the long run.

Selecting option 1 for the pricing rule has implications for the choice of option in the overall auction design. [56] Of the current proposed options only Options B and E necessarily include an unconstrained run by design, whilst in Options A, C and D additional, unconstrained modelling of the auction results would be necessary to identify an unconstrained auction price. Under option A, the TSO would pre-select units required for system reasons and the clearing price would therefore reflect the removal of these units from the auction. Option C would only produce an unconstrained merit order as a by-product, if an unconstrained run were the starting point for the heuristic algorithm, which is not certain and depends on the heuristics implemented. Option D would not produce any unconstrained merit order, but only a constrained outcome: the TSOs would have to run the auction solver separately without constraints to produce an unconstrained merit order (and to compare the constrained and unconstrained runs to decide who was constrained on or off). Our proposed hybrid of Options B and E for the auction is compatible with the selection of option 1 for the pricing rule: our proposal consists of an initial unconstrained auction from which it would be simple to derive the auction price, followed by bilateral

[54] Consultation Paper, para 3.3.8.
[55] NERA Memo, 22 September 2016, pages 7-8.
[56] NERA Memo, 22 September 2016, page 7.

contracting for “must-not exit” generators at prices that reflect their costs and the need to earn a return on investment. We set out our proposal in more detail in our answer to question 3.6.1 above.

3.6.3 Should a bidder that would have been accepted in an unconstrained auction but which is not awarded an RO receive a “constrained-off” payment in the CRM?

For the reasons outlined in this response Energia recommends that capacity auctions are unconstrained and therefore the concept of being ‘constrained-off’ should not apply.

If the SEMC proceed with a decision that results in “constraining off” generators without compensating them[57] it will have a detrimental effect on investor confidence and financeability in this market. It will undermine incentives for efficient investment in the transmission system, will act as a barrier to future investment in generation, and is highly likely to be disputed by disaffected parties. These issues are discussed further below.

The incentive for the RAs and TSO to efficiently manage, and invest in, the transmission system requires an accurate and transparent valuation of the cost of system constraints. Such a valuation will only occur if “constrained off” generators in a capacity auction are properly compensated – i.e. either by the award of a capacity contract via an unconstrained auction, or the implementation of an appropriate compensation mechanism. Removing this important market determined signal by denying compensation for constraints will significantly undermine incentives to efficiently manage, and invest in, the transmission system. Taken in conjunction with the heightened perception of regulatory risk that would accompany it, such a policy change would impose significant long term costs on consumers.

Energia has consistently maintained that the SEM as an *unconstrained* market should have clear and strong locational signals. During the lengthy debate on Transmission Loss Adjustment Factors (TLAFs) over the period from 2009 to 2012 we put forward the rational thesis that locational signals should be strengthened, not weakened[58], as was particularly apparent following the investment of generation assets in the wrong location. The topography of plant on the system today is a direct reflection of the historic locational signals regime the RAs and TSOs put in place, and chose to weaken rather than strengthen (e.g. compressed TLAFs).

Therefore delivering a sharp, unanticipated locational exit signal to “constrained-off” generators in the midst of their investment cycle, as would be the case under options C and D, as well as options A and potentially E, represents a fundamental change to the established regulatory framework. Implementing such a change would seriously undermine the revenue adequacy of the generators concerned and thereby substantially increase the perception of regulatory risk associated with investing in the all-island market that would persist well into the future.[59] This would dramatically increase the

[57] Either directly via the CRM auction mechanism (as in options C and D), ex-ante (as in option A), or ex-post (as could be interpreted as the intention under option E).

[58] See Energia response to SEM-10-039, SEM-11-098 and SEM-12-024 for details.

[59] There is also a substantial risk it could lead to the disorderly exit of “constrained off” units.

cost of capital and prohibit future investment in this market, undermining security of supply and increasing long term costs for consumers. Implementing 'competitive' market mechanisms that deliver sharp exit signals to “constrained-off” plant within their investment cycle[60] would also bring into clear focus any flaws in the historic locational signal regime.

It would be fundamentally unfair, and may be susceptible to legal challenge[61], to try to correct this historic error now by implementing a partially constrained capacity auction that could deliver inefficient exit signals[62] – i.e. by de-selecting units that may later be identified as “must-not exit” after a comprehensive analysis of system security requirements by the TSOs. Furthermore, a generator that appears to be unnecessary now may turn out to be valuable in the future, for reasons that cannot be envisaged at the time of a capacity auction, particularly a T-4 auction.[63] Not providing compensation to units “constrained off” (in the capacity market) by an imperfect selection mechanism, as envisaged under options A, C and D, is also contrary to the stated rationale for a capacity mechanism within the all-island context – i.e. to avoid market failures that would significantly undermine investor credibility in the stability and strength of the regulatory regime. This is a potentially serious issue in a small market with a high level of wind penetration, which increases investment payback periods.[64]

If yes, how should the “constrained-off” payment be determined, and why?

Constrained-off generators should be compensated at the market clearing price for capacity, simply by respecting the results of the unconstrained auction, as in Option B and our recommended hybrid option.

Three of the SEM Committee’s criteria are relevant to the determination of any constraint payment:

To promote security of supply, compensation for constrained-off generators should be sufficient to enable them to cover their costs and remain available. If the compensation is below the level required to keep generators available, they will close and consumers will receive no benefit for the compensation provided.

In order to meet the SEM-Committee’s proposed criterion of equity, constrained-off generators should be paid the same as other “in merit” units.

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[60] Investment in this context refers not just to the initial investment in a plant but also the significant ongoing investment in its maintenance, operation and upgrade.

[61] For example, not to compensate constrained off generators would on its face appears to be non-transparent and discriminatory of generators which are best placed, according to the auction, to provide capacity to the system as a whole, as opposed to a particular location.

[62] Exit signals may be inefficient because they are determined by a simplified representation of system constraints as modelled in the options.

[63] For example: the catastrophic failure of another generator or a transmission facility; unexpected growth or decline in a major demand; changes in transmission operating standards. Therefore assumptions around forecast constraints used in auctions may result in spurious accuracy that could have unfortunate commercial consequences in the longer term, such as the inappropriate exit of units later required because of a change in system circumstances; a situation that could easily arise within a small, highly constrained market such as the I-SEM.

[64] For further details, see Energia response to SEM-14-008 of 4 April 2014 and the I-SEM HLD Impact Assessment SEM-14-085b of 17 September 2014.

In order to promote efficiency, compensation for constrained-off generators should avoid distorting bidding incentives, so that the lowest cost plant are selected in the auction process.

Neither of the SEM-Committee's proposed options for the constrained-off payment meet these criteria.

The SEM-Committee appears to have designed Option 2 by analogy to payments for being constrained off in the energy market that are equal to the lost profits of infra-marginal units. However, the energy and capacity markets differ in both the time period over which this lost profit (or "infra-marginal rent") is paid and the costs that are avoided by the generator:

- In the energy market, the generator is paid the energy price but pays back its marginal costs to the TSO. This results in the generator being paid its infra-marginal rent which compensates the generator for lost profit in any given half-hour as the generator avoids its marginal costs by not generating in that half-hour alone. Under this mechanism the generator will remain available to sell electricity to the TSO in future half-hours because it will be compensated whenever the transmission system is congested.
- In the capacity market, similar compensation would cover the generator's lost profit over *the length* of the *contract* (which is one year for existing generators) in the hope that it will be still available to compete for future contracts. That hope relies on the assumption that (1) the compensation *plus* (2) the infra-marginal rent the generator earns in the energy market will be enough to cover (3) the fixed costs it would avoid by closing. However, that assumption is unlikely to hold, since the combined infra-marginal rents in the energy and capacity markets are likely to be low, whilst the avoidable fixed costs of keeping plant available are high.

Merely compensating constrained-off plant for their lost profit (infra-marginal rent) in the capacity market will therefore lead to plant closure and consumers will not benefit from increased security of supply. However, unlike a decision not to supply energy, a decision to close down capacity at an existing generator cannot easily or cheaply be reversed in the next contract period.

Option 3 proposes compensating constrained-off plant at their bid in the capacity market. Provided that generators bid their costs in the capacity market, option 3 would provide sufficient compensation to constrained-off generators to remain on the system. However, as NERA describes in section 6 of its Memo, if constrained-off generators are paid-as-bid they will have incentives to distort their bids upwards (to obtain a higher constraint payment) or downwards (to remain selected, so that they obtain the capacity market clearing price). Designing an auction where market participants have an incentive to distort their bids is unlikely to result in an efficient mix of plant on the system.

On the other hand, under the SEMC's current proposals, constrained-off generators earning the market price would have no obligations to remain on the system or to pay rebates under the RO. Generators who received compensation at their bid or at the market price could still close and would not have to shoulder the burden of paying the system operator when market prices were high.

Option B and our proposed hybrid of option B and E resolves the failings of Options 2 and 3 above by running an unconstrained, pay-as-clear capacity auction. All in-merit plant earns the capacity market price and takes on the obligations of the RO. In a second stage, the TSO contracts bilaterally with the additional plant necessary for system security. No plant is constrained off and no compensation is required. We provide a detailed description of our recommended hybrid option in our answer to question 3.6.1 above.

3.6.4 How should local capacity deliverability constraints be defined?

For the reasons outlined in previous answers Energia recommends that a hybrid of options B and E is implemented as set out in our answer to question 3.6.1 above.

If the SEMC proceeds with any other option (with the exception of Option E), then extensive analysis would need to be conducted to confirm that the simplified set of constraints modelled for the capacity auction will closely approximate the outcomes from a full system security analysis conducted by the TSO for the reasons set out in our answers to questions 2.6.2 and 2.6.4 above.

Section 4 – Modelling of Constraints for T-1 and T-4 Auctions

4.4.1 Should the inclusion of locational capacity delivery constraints in the CRM occur in T-1 auctions, T-4 auctions, or both?

Energia recommends that a hybrid of options B and E is implemented whereby CRM auctions are run on an unconstrained basis, the TSO then conducts an ex-post full system security assessment to identify any additional units not selected via the CRM but required for reasons of system security;[65] finally that the TSOs conduct a bilateral contracting process to secure the continued operation of "must-not exit" units. For the avoidance of doubt, similar to Option B the continued operation of any additional units secured via bilateral contracts under this hybrid option would not result in de-selection of other 'in merit' capacity.

As the auction process under our proposed hybrid option is unconstrained locational delivery constraints would not be modelled in either the T-4 or T-1 auctions. The risk of inappropriate located entry could then be managed via a robust locational signals regime and via the grid connection process which feeds into the qualification process for the CRM.

[65] For the avoidance of doubt a full system security assessment by the TSO should include all constraints on the power system including any arising due to locational requirements for the provision of system services. This is how reference to a full system security assessment should be understood throughout this response.

4.4.2 What circumstances or criteria should be considered in relation to the T-4 auctions being conducted without explicit consideration of locational capacity delivery constraints?

Regardless of the approach adopted it is highly likely that the TSOs will need to conduct an ex-post full system security assessment to identify any additional units not selected via the CRM but required for reasons of system security and conduct a bilateral contracting process to secure the continued operation of "must-not exit" units. Given this is the case it is unclear that there is a strong case to model locational capacity delivery constraints in either the T-4 or T-1 auctions for the reasons set out in this response.

4.4.3 Are there any further considerations that should be taken account of regarding the longer term management of locational capacity delivery constraints? If so please detail your rationale for these.

Energia would emphasise that for reasons of system security, and regardless of the option implemented for CRM auctions, it is highly likely that the TSOs will need to conduct an ex-post full system security assessment to identify any additional units not selected via the CRM but required for reasons of system security and conduct a bilateral contracting process to secure the continued operation of "must-not exit" units. A pragmatic approach would therefore be to allow the TSOs to conduct this analysis after both T-4 and T-1 auctions and enter into longer term contracts with "must-not exit" units in appropriate circumstances. This would relieve pressure on the TSOs relative to conducting such an assessment and contracting only after T-1 auctions,[66] and would also help reduce costs and improve efficiency by removing uncertainty. Such a flexible approach would also greatly help to ensure continued security of supply. We would also emphasise that the risk of inappropriate located entry could also be greatly reduced through a robust locational signals regime and via the grid connection process which feeds into the qualification process for the CRM.

Section 5 – Market Power

5.1.1 Do you believe that the suite of market power controls set out in CRM Decision 3 are sufficient to address any additional market power issues raised by local security of supply considerations? If not, what additional measure would you propose, and why?

Comment on CRM Decision 3

In our previous submissions on market power controls (for the energy market), we have stressed two important points, each reflecting the problem that overly restrictive controls hinder competition and harm efficiency. These points are equally relevant to the capacity market:

- That price controls should allow generators to earn a reasonable return on past investments, as well as to recover future avoidable costs ("Net Going Forward Costs"); and

[66] Under current timelines for T-1 auctions we don't believe this would be practical anyway and would jeopardise security of supply.

- That market power controls should be targeted on the dominant player (i.e. ESB).

The first of these points is particularly important in the capacity market, where the annual contract presents an artificial time constraint on the remuneration of existing generators' costs. In order to remain available, existing generators will have to invest in maintenance and in major refurbishments, the benefits of which last for several years. If such investment does not reach the threshold for new capacity (i.e. the generator is unable to bid for a long term capacity contract) the cost of these investments would appear as very high "Net Going Forward Costs" within the year when they are incurred (potentially pushing the generator out of merit in a capacity auction). However, if the generator spreads these costs across a number of auctions, the costs would immediately be disallowed in the calculation of "Net Going Forward Costs". This consequently would deter investment and undermine security of supply.

Offering generators the prospect of earning a return on investment, in addition to short-run operating costs, is therefore essential for encouraging existing plant in constrained areas to remain on the system. In the absence of any return on past investment (a sunk cost), the SEM Committee's estimate of Net Going Forward Costs puts plant closure decisions on a knife edge: plant would remain open if the estimate was adequate; if the SEM-Committee underestimated Net Going Forward Costs for a particular plant by any amount, however small, the plant would have an incentive to close irreversibly. To ensure system security, consumers would then have to pay for long term contracts with costly new plant – an inefficient outcome.

The concept of "Net Going Forward Costs" is therefore entirely unsuitable for defining an "Auction Price Cap" and is unduly restrictive (too low) as a basis for allowing offer prices above the "Price-taker Offer Cap".

As evidenced by the discussion of the market clearing price and the ex post adjustments to any auction outcome, the I-SEM capacity market will be too complex to permit the adoption of simple price caps, such as those proposed by the SEMC, without severely hindering competition and harming efficiency as a result.

<u>Comment on Proposals in the Consultation Paper</u>

In the current consultation, the SEMC has adapted its general proposals to the specific case of local market power, and sets out three alternative proposals for restricting "the bids of any plant required for local security of supply reasons", namely:

a. "At its individual Net Going Forward Cost, i.e. below the Uniform Price-taker Offer Cap if its individual Net Going Forward Costs are lower than the Uniform Price-taker Offer Cap; or

b. At the Uniform Price-taker Offer Cap adjusted for any specific ancillary service payment it may receive.

c. Any individual plant could be required to have an evaluation of its Net Going Forward Costs due to fear of economic or physical withholding, at the discretion of the SEM Committee."[1]

We anticipate problems with the proposed rules for incentives and efficiency as explained in more detail below.

Option "a" would prevent affected generators ever obtaining a price above their Net Going Forward Costs. This rule would fall foul of the objection described above, whereby the plant would immediately be disqualified from recovering the cost of long term investment incurred for maintenance and refurbishment (if the investment cost was below the threshold for new capacity), let alone making a return on any other investments. This rule is therefore inefficient. Furthermore, from the point of view of equity, we can see no reason why plant that is known to be especially well located should face a price cap lower than that faced by other plants, just because its costs are below the Auction Price Cap. That approach seems to be discriminatory. Such discrimination would be exacerbated by the incentive for the TSO to identify all cheaper generation as being required for local reasons, simply so that it can pay less than otherwise (or maybe even less than the market price). Option "a" therefore seems to be entirely unsuitable.

Option "b" would impose a cap on the offers of plants required for local reasons at the Uniform Price-taker Offer Cap, less any ancillary service revenues. The SEM Committee does not explain its rationale for capping at this level and we foresee a potentially severe problem: this cap may lie below the costs that the plant needs to recover. At the very least, there would need to be provision for exceptions. Moreover, we foresee a practical problem with implementing this proposal. We assume that the Uniform Price-taker Offer Cap would reflect the maximum level of unrecovered costs that price-takers need to recover from the Capacity Remuneration Mechanism. In principle, price-takers' unrecovered costs would already include a deduction for their expected revenue from the sale of energy *and ancillary services*. The proposed rule therefore runs the risk of deducting ancillary services revenue twice over, once in the calculation of unrecovered costs, and once in the calculation of the price cap.

Option "c" seems to differ from option "a" only in that the SEMC has discretion over whether to apply the price cap or not. As previously noted however, the concept of Net Going Forward Costs is unsuitable as a basis for setting price caps in the capacity market and while the impact would be less than under option a due to the discretionary nature of the intervention, it is still inappropriate.

Advantages of Our Proposed Hybrid Option

Under our proposed hybrid option, no additional market power controls would be necessary for constrained-on plant in the auction process itself. Plant with local market power would be unable to obtain an RO through the unconstrained auction if it bid above the market-clearing price. After the

[1] Consultation Paper, paragraph 5.2.5. We have added the list numbering for ease of reference.

auction had closed, the TSO would ensure that sufficient capacity remained operational in constrained areas through a separate contracting process. That process would allow the TSO to consider all the relevant costs and the appropriate price to pay. For long standing system constraints initiating the contracting processes in advance of T-1 auctions may also allow the TSO to consider other potential solutions, including investments to alleviate transmission constraints, thereby further reducing the potential to exploit local market power.

Avoiding the need to calculate cost-based bid caps for each plant in constrained areas represents a considerable simplification. Compared with proposals for general (or even market-wide) price caps, this aspect of our proposed hybrid represents a procedural advantage that enhances its practicality. It also allows more market-based competition between generators and other sources of capacity, and hence achieves higher efficiency.

Annex 1 - The All-Island Market Structure

The all-island electricity market of the Republic of Ireland and Northern Ireland is relatively small, constrained and isolated, it is highly concentrated and dominated by the state-owned incumbent ESB, and it has a high and growing penetration of wind on the system. These aspects of the market structure, detailed further below, were important considerations in the design of the Single Electricity Market and its capacity mechanism and are equally relevant in the context of market re-design under I-SEM based on the fundamental policy needs to ensure security of supply, promote competition and meet renewable targets.

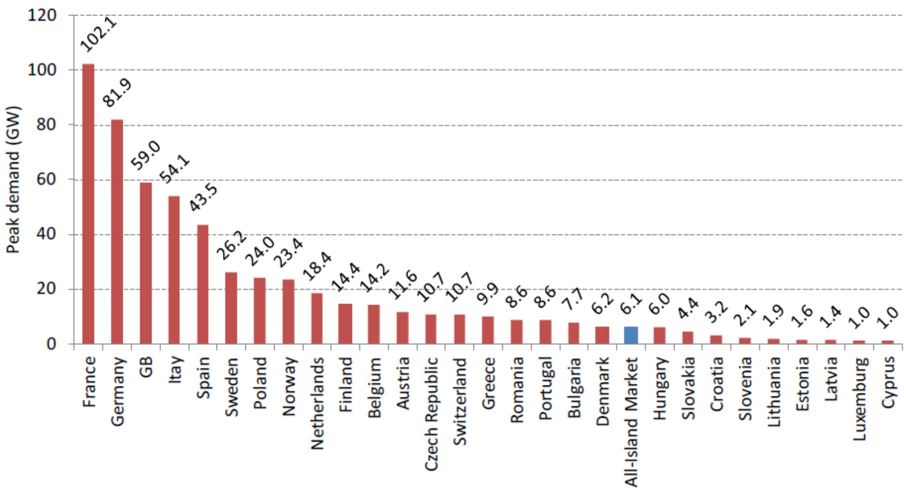
Small Isolated Market

The all island market is a small synchronous system, with no AC interconnection to any other market. It is only interconnected to GB by two long distance sub-sea DC interconnectors, the Moyle and more recently the East West Interconnector, which are demonstrably susceptible to prolonged outages if compromised.

Peak demand in the SEM reached 6.2GW in 2012 with total annual electricity demand of 34.5TWh (equivalent to average hourly demand of 3.9GW). The figure below compares the level of peak electricity demand in the SEM with that in a number of selected European markets. It illustrates that the SEM is one of the smallest electricity markets in the EU, with the only other smaller markets either being:

- Small island systems with no external interconnection – Malta and Cyprus
- Part of the synchronous area of continental Europe with AC interconnection capacity with neighbouring countries – e.g. the Baltic states, Slovakia, Hungary, Luxemburg, Croatia and Slovenia.

Peak Demand of European Markets in 2012



Source: SEM Committee (SEM-14-008, page 12)

The small size of the all-island market generates a concern about the sensitivity of the capacity margin to plant entry and exit, which has supported the use of an explicit CRM in the design of the SEM.

Market Dominance

The all-island market is highly concentrated by European standards in both electricity supply and generation. Recent market shares presented by the SEM Committee in the figures below show that ESB, the state owned incumbent, has a share that would be consistent, for the purposes of competition law, with a dominant position in installed capacity and super dominance in Contracts for Difference (CFDs). ESB has the largest market share in both generation and supply segments (Electric Ireland is owned by the ESB Group) and has three times as much installed capacity as its competitors by any measure presented by the SEM Committee. It should also be recognised that unlike its principal competitors, ESB has a highly diversified portfolio of generation, including coal, peat, gas, wind and hydro plant. Consequently, some of ESB's plant is likely to be generating in all conditions, reducing ESB's residual exposure to the outturn level of demand.

SEM Market Shares in 2014

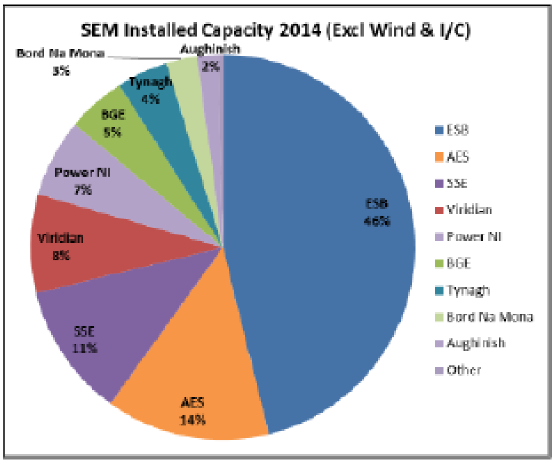


Figure 1

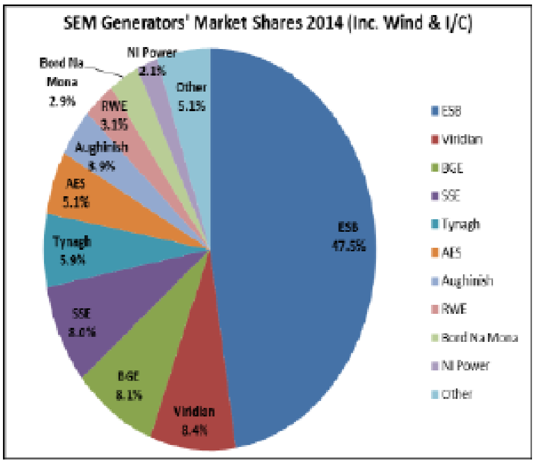


Figure 2

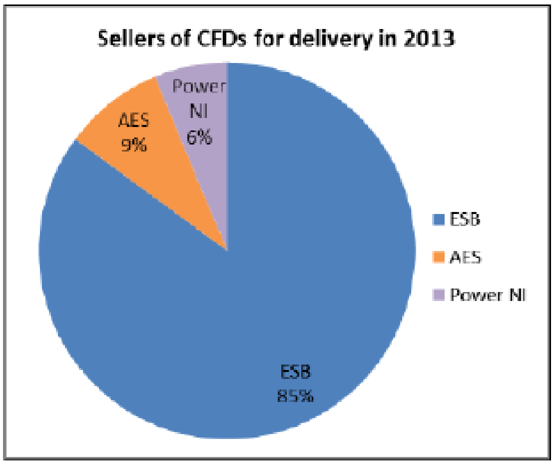


Figure 3

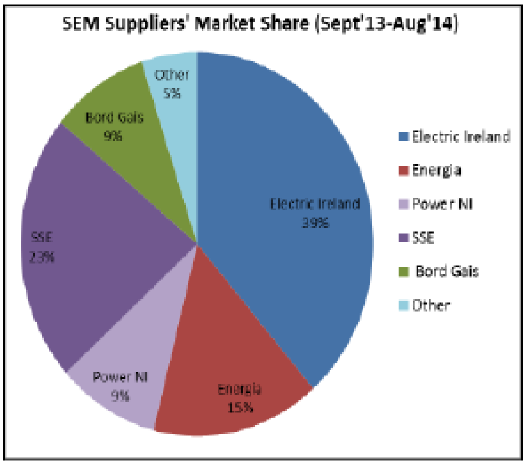


Figure 4

Source: *SEM Committee (SEM-15-031, page 15)*

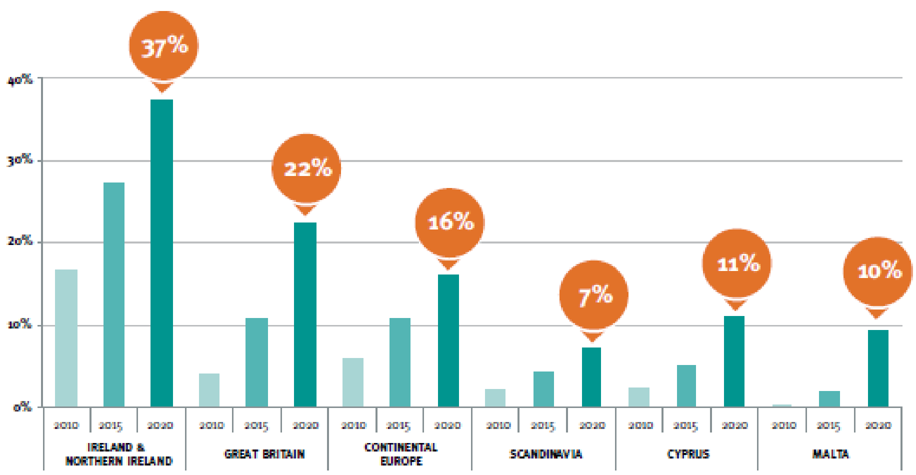
The principal source of potential market power in the all-island market therefore remains the dominance of ESB. Dominant players can inhibit competitive markets reaching socially optimal outcomes, a market failure. Because of ESB's position as a large, state-owned company, it is necessary to consider the possibility of ESB using its market power to achieve political objectives, rather than to raise its profits. This is because as a state-owned company, ESB may not operate with entirely commercial objectives. For instance, it may come under pressure to lower energy prices, leading to predation, or it may be driven by management objectives to maintain or expand its market share, even when it would be unprofitable to do so. Whilst such behaviour might appear ostensibly desirable from a political perspective, it would be unfavourable to competition and need not be in the interests of all electricity consumers in the all-island market.

The risk of regulatory intervention in the market is accentuated by market power concerns and the difficulty of distinguishing between exertion of market power and scarcity prices. State owned dominance in the wholesale and retail markets also gives rise to a strong perception of non-commercial objectives and that prices are implicitly capped. Concerns about the scope for market power were an important driver of the SEM design, including the reliance on a transparent, liquid and cost reflective ex-post pool combined with an explicit capacity payment mechanism.

High Penetration of Renewables

The Governments in both jurisdictions have a target of generating 40% of electricity consumed from renewable sources by 2020 and a large proportion of this will come from wind. In order to meet these 40% renewable targets it is projected by EirGrid that the amount of wind generation across the island of Ireland will reach an installed capacity of between 4,800 MW and 5,300 MW by 2020 [EirGrid Annual Renewable Report 2013]. At this level, Ireland and Northern Ireland will have one of the highest penetrations of renewable generation, as a percentage of system size, in the world. Currently the instantaneous penetration of wind on the system reaches 50% more often than ever before. In 2012 renewable generation supplied 17% of electricity demand on an all-island basis and installed wind generating capacity in Ireland and Northern Ireland reached 2,252 MW. The high penetration of renewables results in less revenues for other generation types based on reduced market running.

PENETRATION OF NON-SYNCHRONOUS RENEWABLES
IN EACH EUROPEAN SYNCHRONOUS SYSTEM 2010-2020

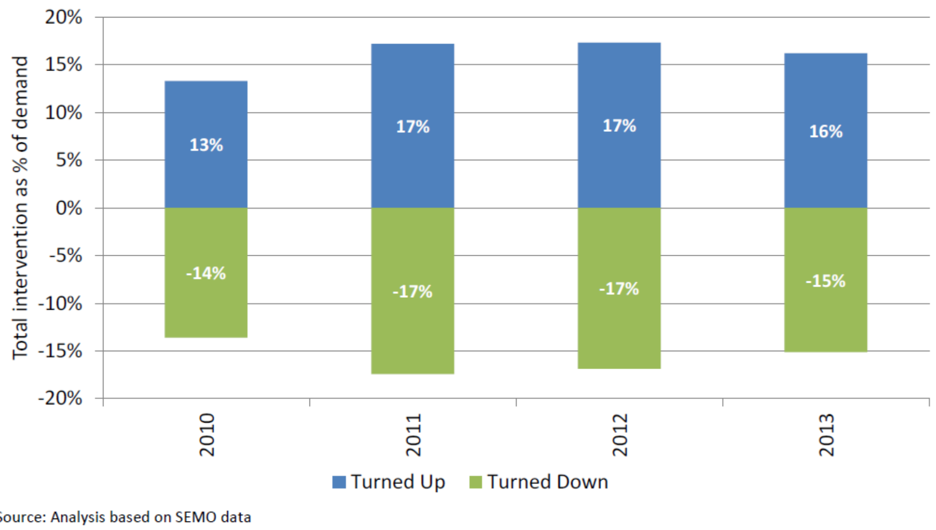


Source: The National Renewable Energy Action Plans (NREAP)

System Operational and Constraint Challenges

Management of transmission and system security constraints is an important aspect of the system operator dispatch process in the SEM. This is because of locational physical transmission constraints and the importance of non-energy related issues (such as system interia and frequency response) in managing the small synchronous island system, particularly with a high penetration of wind and a relatively large swing in demand within the day between peak and off-peak hours. This leads to large differences between the ex-post market schedule and the system operator dispatch, as demonstrated in the figure below which shows the extent to which plants were re-dispatched (in both directions) away from their scheduled quantities between 2010 and 2013. Reduced market running associated with a high penetration of (non-synchronous) wind generation results in less revenues for other generation types but yet non-energy services and binding transmission constraints require such plant for security of supply. This presents a revenue adequacy challenge relevant to considerations of a capacity mechanism.

Constrained Running (Difference between schedule and dispatch)



Source: SEM Committee (SEM-14-008, page 16)