Response by Energia to SEM Committee Consultation Paper SEM-16-073

I-SEM Capacity Remuneration Mechanism Parameters Consultation Paper

21 December 2016

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Executive Summary

This Consultation Paper is of critical importance to generators and to the subsequent success of I-SEM. Energia objects strongly to the proposed regulatory measures which go far beyond constraining market power in capacity auctions. The proposed measures would have the direct and very material effect of denying generators the opportunity of recovering their total costs in the market, thereby hindering the development of a sustainable competitive process and endangering security of supply to the detriment of consumers. This is contrary to the regulators' duty to promote competition and protect the interest of consumers and ensure that licensees can finance their activities.

Our concerns with respect to cost recovery are heightened by the expectation that our own plant at Huntstown, which is a significant and reliable resource at the disposal of the TSO, is likely to be designated as Must Run Reliability plant (or "constrained-on" plant). Such plant is required to support the system, but inevitably has higher costs than in-merit plant (or else it would be in-merit itself). In the I-SEM markets for capacity and energy, constrained-on plant will receive the price that it bids, rather than the clearing price[1]. The proposed limits on offer prices across all relevant markets would prevent these plants from earning additional market revenues (i.e. Inframarginal Rents) over and above the costs they are allowed to include in their offer prices and prevent the recovery of total costs[2].

Supported by legal inputs from Arthur Cox and an expert economic report from NERA[3] ("the NERA Report"), Energia's response highlights significant and fundamental flaws in both the proposed approach and the options put forward by the SEM Committee in this consultation. Having reviewed the SEM Committee's proposals to restrict bidding behaviour in the I-SEM capacity market, taking into account bidding controls in the I-SEM balancing market, the NERA Report states that *"[t]he SEM Committee wrongly claims support from regulatory precedent for its suite of market power controls. In practice, the regimes on which the SEM Committee relies differ from its own proposals in ways that allow generators the flexibility to earn a contribution towards their fixed costs by other means – means that are denied in the I-SEM proposals".* (p 8)

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[1] The method of pricing ancillary services is of little importance in this context. Generators cannot rely on a stream of net income from sales of ancillary services, even at tariff rates, to fund investment in generation capacity. In any case, under the current proposals, any forecast margin earnt from selling ancillary services is deducted from the allowed costs that may be included in capacity market offer prices according to the RAs' prescriptive definition of NGFC.

[2] Generators that are constrained-on are likely to have relatively high costs (otherwise they would not be constrained-on) and therefore their Net Going Forward Costs are likely to lie close to, if not above the Existing Capacity Price Cap.

[3] NERA (2016b), Competition and Cost Recovery under the I-SEM Bidding Rules: A Report for Viridian, 19 December 2016.

NERA concludes:

"Overall…the SEM Committee's current proposals for the capacity auction would be detrimental to consumers' interests." (p12)

This response and the NERA Report demonstrate why that is the case.

The SEM Committee's unduly restrictive approach is flawed and will harm competition

Competitive market pricing requires flexibility to price above variable costs so that the competitive process can flourish. Ruling out such pricing would hinder the competitive process and deny generators a legitimate means to recover their costs. However this is precisely what the regulatory authorities are proposing to do in I-SEM, which is contrary to their statutory duty to *promote competition*.[4]

In practice, competitive markets operate in a complex manner, and, in this complex environment, promoting competition means facilitating the *competitive process* and preventing overt market abuses, not dictating a particular outcome based on a narrow (and flawed) view of allowable costs. The SEM Committee's view seems to be based on the notion that mitigating market power requires electricity markets to be regulated on the basis of the cost-of-service[5].

As NERA explain, *"The SEM Committee has chosen to apply a market outcome based on a flawed interpretation of the theoretical ideal of perfect competition, which is not even applicable to sectors with long run, irreversible investments…in real world conditions, competition authorities promote competition by helping the competitive process to reveal competitive market outcomes, rather than by imposing a particular outcome"* (p1)

The NERA Report explains that the SEM Committee misapplies the concept of "missing money" and discusses it in terms of *costs* (specifically, a failure by generators to recover the SEMC's view of Net Going Forward Costs in capacity markets and/or their Short Run Marginal Costs in energy markets), instead of discussing any potential shortfall in *revenue* relative to a competitive market price, as should be the case.

In this context, the cost-based approach being pursued by the RAs is not consistent with allowing – let alone promoting – competition, and is not a form of regulation the RAs have the power to decide. It also undermines cost recovery as explained further below.

[4] Under the Electricity Regulation Act 1999, the CER must protect the interests of consumers of electricity wherever appropriate by promoting competition. The CER has also a duty to have regard to the need to promote competition in the generation and supply of electricity.

[5] Where this 'cost-of-service' is incorrectly and narrowly defined by the SEM Committee.

The SEM Committee is denying generators the opportunity to recover their total costs

The whole package of market rules must offer *all* market participants the opportunity to recover their *total* costs – including sunk costs, operating expenses and the cost of capital – in order to maintain incentives for efficient investment and provide efficient outcomes for consumers. We have now had the opportunity to review the SEM Committee's proposals for every part of the I-SEM, i.e. the markets for capacity, energy and ancillary services ("DS3"). Apparently because of fears over potential market abuse that would increase prices[6], the designers of each part of the I-SEM have imposed tight restrictions on the costs that generators can include in their offer prices – and, in some cases, in the prices they are paid. In some cases, the designers assume that generators can adequately recover the other costs in some other part of the market, but without checking the truth of that assumption. Energia does not believe that the regulatory authorities' approach complies with their statutory obligation to have due regard to the need to ensure that generators are capable of financing their licensed activities (or promoting competition). In fact, for many generators, the whole package of market designs is proving to be so restrictive that, altogether, it will deny any prospect of total cost recovery, both by disallowing specific costs in every market, and by leaving no opportunity for generators to otherwise recover these costs. This is particularly obvious when considering generators who are likely to be required for system security or "constrained-on", as discussed further below.

The case of "constrained-on" generators

I-SEM will determine a single, market-wide price, as if transmission constraints did not exist; higher cost ("out-of-merit") generators, that must run behind actual transmission constraints to support the system, will be paid their own offer prices for their capacity and for the energy they generate under the SEM Committee proposals. For some generator capacity, most of its revenue will come from sales as a "constrained-on" generator, at its own offer prices. Such a generator will only be able to recover all of its costs from sales of capacity and energy *at its own offer prices*.[7] This will only be possible if the definition of allowed costs and offer prices is sufficiently flexible, but the SEM Committee's proposed restrictions for mitigating market power in the I-SEM capacity and balancing markets offer no such flexibility. In this case, as NERA confirm, *"[t]he SEM Committee's rules therefore explicitly forbid certain*

[6] At the same time, the lack of proposals to properly deal with predatory behaviour is remarkable given the current market structure.

[7] Sales of ancillary services at fixed tariffs may provide another means to cover fixed costs, but cannot be relied upon. For individual generators, the volume of sales of ancillary services is highly uncertain and the whole "DS3" regime may change shortly from tariffs to one more reliant on generator bids. In any case, under the current proposals, any forecast margin earnt from selling ancillary services is deducted from the allowed costs that may be included in capacity market offer prices according to the RAs' prescriptive definition of NGFC.

existing plants [that are constrained on] to recover any sunk costs of investment". (p11)

Perversely, it is the very plant most needed for system security being restricted the most. We recently discussed the legal framework surrounding this issue in our response to the SEM Committee's consultation paper on Offers in the I-SEM Balancing Market (SEM-16-059) and draw from that again here. In that response, Energia opposed the proposals put forward by the SEM Committee for restricting offers in the balancing market in the strongest possible terms. We provided evidence that the proposals were economically, legally and procedurally flawed and, with reference to the importance of the outcome, that any decision on the basis of that consultation and/or the subsequent process to modify generators' licences would be susceptible to challenge. Regrettably, we find ourselves in a similar position with respect to the current Consultation Paper which continues the perilous path of denying total cost recovery, particularly for constrained-on generators needed for system security.

The SEM Committee's denial of total costs is unjustified

Under the current consultation proposals for the I-SEM capacity market, the SEM Committee would prescribe a restrictive list of costs that may be included within Net Going Forward Costs. As currently proposed, this list *excludes* sunk costs, some relevant avoidable costs, and makes no provision for cost items "not elsewhere specified". Energia objects strongly to these measures being implemented on the grounds that they would expressly deny generators, including the Huntstown plant, the opportunity of recovering their total costs.

The need to allow recovery of sunk costs is part-and-parcel of the regulation applied to energy networks and other permanent monopolies throughout the island of Ireland. Significantly the European Commission's Energy State Aid Guidelines require that, in order for aid to be compatible, the scheme must "*not undermine investment decision on generation which preceded the measure"* (paragraph 233).[8] Recovery of sunk costs is a pre-condition for *credible* incentives to invest in efficient, long-lived, irreversible assets. The necessity of recognising sunk costs does not evaporate when a regulatory regime is applied to a market instead of a monopoly. Market prices may rise or fall, but there is never any justification for a regulatory regime whose pricing rules systematically disallow sunk costs.

Such a regulatory regime pays no regard to the need to ensure that generators are capable of financing their licensed activities and is

[8] The US obliges government agencies to provide the opportunity, at least, for investors to recover all their costs, including sunk costs of investment, operating expenses and a fair rate of return. This obligation is derived from an interpretation of constitutional property rights, but is recognised as desirable *per se*, because it works to the *public* good (not just to the benefit of investors).

irreconcilable with the constitutional protection awarded to property rights. It would be incompatible with the regulatory authorities' statutory objectives and their duties to encourage efficiency, to promote competition, and to foster security of supply.

Disallowing sunk costs will discourage future investment

The current Consultation Paper only denies the need to recover the sunk costs of "existing investors", as if such costs formed a special category because they were incurred before the current date. However, for investors in long-lived assets that operate under a permanent (albeit evolving) regulatory regime, there is no such thing as a special date, before which "past" costs can be ignored whilst "future" costs are avoidable (and must be remunerated). A regulatory policy of disallowing, or even just ignoring, sunk costs will inevitably discourage future investment. As NERA explain, *"…no regime that regulates continual investment can disallow the recovery of sunk costs on principle…Treating the same costs inconsistently at different times undermines the credibility of the regime and destroys incentives for long term investment. Such rules do not represent pricing behaviour in a competitive market either, and can never produce an efficient outcome".* (p11)

In practical terms, investors in new capacity will seek to recover their entire costs of (and return on) investment over the course of a maximum 10 year capacity contract, knowing that these costs will be deemed 'sunk' thereafter and hence non-recoverable.

Disallowing sunk costs will also discourage efficient plant upgrades

In order to remain available, existing generators will have to invest in maintenance and in refurbishments, the benefits of which last for several years. If such investment reaches the New Capacity Investment Rate threshold, it would be eligible for a long term capacity contract, but in our view it will be impossible to reach the high threshold as currently defined. If such investment does *not* reach the New Capacity Investment Rate threshold, 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.

We note that the SEM Committee have not provided any evidence on the actual costs of lifetime extension works for the fleet of plant on the island. Such an exercise must be conducted to ensure the New Capacity Investment Rate threshold is set at an appropriate level and based on evidence. The consequences of setting this threshold too high, which it currently is as proposed[9], (whilst denying the recovery of so called 'sunk costs' in capacity market bids) is the inefficient closure of existing plant. To ensure system security, consumers would then have to pay for long term contracts with costly new plant. This is also the conclusion reached by NERA, *"[in some cases], low cost existing capacity will be replaced by more expensive new capacity, just because it is able to obtain a long term contract. Such choices would be inefficient and the possibility of delays in construction would put security of supply at risk".* (p12)

Grid Code requirements

The current consultation paper repeatedly points to the Grid Code requirement to give 3 years' notice of plant closure as a reason to expect the Capacity Requirement to be met during the transitional period of I-SEM. However, for reasons set out in our response to the Locational Issues Consultation (SEM-16-052), the SEM Committee may not lawfully maintain such a notice period for which no justification has been provided in circumstances where it conflicts with the objectives being pursued with the I-SEM design, including in particular ensuring that appropriate entry and exit signals are given to generators. Even if such a requirement was maintained, then it is the duty of the SEM Committee to ensure that the provision of capacity available as a result of the three years' notice requirement is remunerated adequately in accordance with the statutory duty of the RAs to ensure that licensed generators can finance their activities. A prohibition on exit where the regulatory regime is not calculated to ensure that generators required to maintain capacity available during a notice period are adequately remunerated, as the SEM Committee's proposals imply, would be entirely unjustifiable, unreasonable and disproportionate and constitute an unjust attack on the constitutionally protected generators' property rights. Furthermore, and in any event, it would be futile (not to mention falsely reassuring) to rely on Grid Code requirements to keep plant open for system security reasons, if total cost recovery is not also assured.

State aid considerations

The RAs believe that the CRM will involve State aid. We note that the Energy State Aid Guidelines require that in order for aid to be compatible, the scheme must "*improve the functioning of a secure, affordable and sustainable energy market*" (paragraph 49) and "*not undermine investment decisions on generation which preceded the measure*" (paragraph 233). A measure which denies overall cost recovery to existing capacity and restricts existing capacity to only recovering recurrent costs is inconsistent with both these requirements

[9] The proposed threshold is 50% of Gross Cone. We recommend a more appropriate level for this threshold of 10% but that a regulatory mechanism is put in place to allow provision for the SEM Committee to allow exceptions on a case-by-case basis. See summary / response to detailed questions for further details.

and discriminates without valid justification between existing and new capacity.

Greater flexibility is required

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

The desire to prevent market abuse does not require a restrictive policy that defines precisely which of their costs ("NGFC") generators may include in their offer prices and, ultimately, in the prices they receive for their capacity. The SEM Committee cannot rely on "international best practice" to justify this approach, since there is no system in the world that aims (or could ever aim) to foster competition and security of supply with the combination of measures currently proposed for the I SEM's markets in capacity and energy. As NERA confirm, *"international precedents offer no support for the specific form of capacity market price controls currently proposed for the I-SEM, because controls in other markets offers greater flexibility, rely on ex post scrutiny, and do not deny total cost recovery."* (p1)

On the contrary, it will be essential to allow much greater flexibility for the competitive process to work – occasionally allowing generators to bid more than NGFC, because of the necessity of recovering sunk costs. This provision may be defined by allowing for "any other costs not elsewhere specified", or better still by focusing the scrutiny of offer prices on particular cases of suspected abuse ex post, and allowing the competitive process to dictate market pricing whenever possible. Ex post regulation of this type has been effective under the BCOP in the SEM, and represents normal practice in other electricity markets. There are no grounds for adopting a different approach for the I-SEM.

We have provided evidence that the SEM Committee's own consultations show the risk inherent in trying to impose detailed and inflexible ex ante regulation on complex and evolving competitive markets. It is already apparent that (1) the proposed approach is not practical, (2) if implemented, it will not be stable, will generate inefficient outcomes and will hinder competition and threaten security of supply. The only possible conclusion is that a different approach is required to meet the SEM Committee's usual I-SEM assessment criteria, and to comply with the regulatory authorities' statutory duties.

Summary of response to Detailed Questions

- ***Administrative Scarcity Pricing Parameters:*** Option 1 is preferred, at least for a transitional period, given the considerable uncertainty that exists with respect to the functioning of the I-SEM energy trading arrangements in practice, especially given the lack of quantitative analysis or testing during the detailed design phase.
- ***Supplier Charging Base***: Option 3 is preferred, the 'minded to' position of the SEM Committee.
- ***Interest Rate on Socialisation Fund Balances:*** The 12 month LIBOR rate should be used. If the LIBOR is negative this should be set to zero. The SPR and the DPR premiums should have the same values so the fund is cash neutral.
- ***DSU floor price in Strike Price:*** The DSU floor price should be set to cover the prevailing cost of all existing demand side units.
- ***Carbon Intensity Factors for Gas (CIG) and Oil (CIO) in Strike Price Formula and Transport Adders for Strike Price:*** The answer to these questions is contingent on the reference fuel index to be used, but there seems to be no regulatory commitment to consult on this far more important question which needs to be informed by market participants actively trading in the market. We also re-emphasise that the RO Strike Price should be updated *daily*. Using a monthly index unnecessarily increases "scheduling risk" and should be re-considered by the SEM Committee.
- ***Billing Period Stop Loss Limits for ROs:*** The SEM Committee's proposal to set the Billing Period (i.e. weekly) Stop Loss at 0.5 X the Annual Stop Loss Limit fails to provide incentives or limit risk and is therefore disproportionate and damaging to competition. We strongly favour a *lower* Billing Period Stop-Loss Limit and propose that this should be set at 0.125 X the Annual Stop Loss Limit. This would help ensure that losses in excess of capacity revenues are targeted at persistent unreliable generators reducing the risk of a market participant which is typically reliable losing more than its entire year's capacity payment due to an unfortunately timed, but nevertheless rare outage. However it still maintains substantial penalties on generators if not available during a stress event.
- ***New Capacity Investment Rate Threshold***: The proposed New Capacity Investment Rate Threshold is unattainable for refurbishment. A second lower threshold *no greater than 10%* of the gross investment cost of the BNE plant should therefore be introduced, along with provision for exceptions below this threshold on a case-by-case basis.

- ***Termination Fees for New Build Capacity***: Termination fees set at an appropriate level are essential for New Build capacity projects, as a deterrent to capacity hoarding. However it should also be recognised that the main reason for delay on project development in Ireland has been due to non-delivery of electrical or gas connection infrastructure. Developers would therefore need to be protected for delays outside of their control before termination fees crystallise or Bonds/LOCs are called.
- ***Termination Fees for Other Capacity***: Existing capacity should not bear termination fees under any circumstance because they have lower incentives for non-delivery, for example by having to post collateral against RO difference payments, and face obligations that New Build capacity does not.
- ***Performance Bonds***: Energia does not agree with termination fees or performance bonds for existing capacity under any circumstances. Performance bonds for 100% of termination fees (providing that termination fees are set at a reasonable level) is a natural follow on to provide assurance that termination fees will be paid by failed New Build projects and there would seem no reason to vary the calculation methodology for performance bonds by capacity type.
- ***Auction Price Cap***: The proposed calculation of Net CONE makes arbitrary assumptions that are inconsistent with other assumptions and the realities of the market and have the effect of setting offer caps too low, unnecessarily adding to the administrative burden, and significantly increasing regulatory risk regarding cost recovery (for new and existing generators). A stark example is the arbitrary and inconsistent re-definition of security standards, for which no reasons or justification has been provided, to lower capacity market price caps. These shortcomings need to be remedied.

  We also advocate a full re-calculation of Net CONE for the first transitional auction (including the correction of past errors) and thereafter on an annual basis which, for the sake of transparency, needs to be subject to clear rules of governance.

  The proposed multiple of 1.5 x Net CONE for setting the Auction Price Cap lies towards the lower end of international norms, especially since some regimes apply the multiple to the gross CONE (i.e. a higher figure, calculated before deducting IMR). It would therefore be prudent to take a multiple that was towards the top end of the international range for the I-SEM, because of its small market size, the lumpiness of demand and supply growth, and the lack of historic data regarding the new trading arrangements.

- ***Bid Limits (Existing Capacity Price Cap)***: Energia does not support the imposition of an Existing Capacity Price Cap as we believe it to be discriminatory. If the SEM Committee proceeds with an Existing Capacity Price Cap then we recommend it is set at a much higher level than 0.5 x Net CONE to avoid the under recovery of costs, recognising the risks when setting the cap are asymmetrical, with significantly more downside (including administrative burden) resulting from underestimating it than over-estimating. This is particularly the case given the prescriptive ex-ante approach being proposed for the scrutiny and approval of bids exceeding the ECPC in I-SEM. Compare this with GB where neither National Grid nor Ofgem scrutinises the evidence on generator's costs until and unless Ofgem launches an investigation *after* the auction has taken place. Appraising costs *ex post* reduces the scope for error and the risk of imposing price caps below generators' marginal ("forward-looking") costs.

  In the discussion of offer price caps more generally, we see (1) the arbitrary exclusion of legitimately incurred costs (both sunk and incremental); (2) reliance on subjective judgement rather than objective principles; (3) a wide scope for errors in the SEM Committee's forecasts of future costs and revenues; and (4) proposed arbitrary approaches that heighten the perception of regulatory risk. Similar trends can be observed in the presentation of arguments supporting the BMOP.[10] On the other hand, we see absolutely no acknowledgment of the difficulties of determining accurate assumptions or carrying out accurate modelling, or recognition of the limited information that will be available to regulatory staff when carrying out these tasks.

- ***Demand Curve Parameters***: Energia supports the demand curve maintaining the auction price cap up to the capacity requirement and favours Option A, which has the shallowest gradient from net CONE to zero price. Option A will increase the likelihood that additional capacity above the capacity requirement is procured lessening the impact of the 'lumpiness' issue and reducing locational concerns. A shallower demand curve will also help to smooth out volatility in the capacity price, which may otherwise prevent the capacity market from providing a stable, credible investment signal.

- ***Locational Parameters***: Energia agrees that the costs/risks of implementing local demand curves as opposed to a minimum requirement outweigh the benefits.

- ***Load Following for Secondary Trading***: Energia supports measures to maximise available volumes in the secondary capacity market, including load following. In response to questions 7.2.1 and 7.2.2 we offer some

[10] SEM Committee (2016), *Offers in the I-SEM Balancing Market: Consultation Paper,* SEM-16-059, 7 October 2016.

suggestions for refining what has been proposed in the Consultation Paper with respect to load following.

1. Introduction

This document sets out Energia's comments in response to the Consultation Paper on I-SEM CRM Parameters dated 8 November 2016 (the "Consultation Paper")[11], including answers to the questions posed within that paper.

This Consultation Paper is of critical importance to generators and to the subsequent success of I-SEM. Energia objects strongly to the proposed regulatory measures which go far beyond constraining market power in capacity auctions. The proposed measures would have the direct and very material effect of denying generators the opportunity of recovering their total costs in the market, thereby hindering the development of a sustainable competitive process and endangering security of supply to the detriment of consumers. This is contrary to the regulators' duty to promote competition and protect the interest of consumers and ensure that licensees can finance their activities. This response clearly articulates these fundamental flaws and explains our objections, with expert economic support provided by NERA Economic Consulting and legal input from Arthur Cox. In support of this response, we submit a Report from NERA[12] (the "NERA Report"), giving an independent expert assessment of the proposals presented in the Consultation Paper. The NERA Report constitutes an integral part of this response and should therefore be read in full by the RAs. 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 remainder of this response is structured as follows. Section 2 summarises the proposals for capacity auctions in I-SEM that we object to most strongly in this Consultation Paper. Section 3 describes the legal framework within which the I-SEM design must be developed and recalls fundamental principles of welfare economics which govern the promotion of efficient, secure and competitive electricity markets, highlighting the dangers of poorly designed and overly-prescriptive regulation such as that which is currently taking shape under the I-SEM programme. Energia has many comments about the proposed limits on offer prices and auction prices for I-SEM capacity markets. Our concerns are heightened by the expectation that our own plant at Huntstown, being reliable, flexible and located in the constrained Dublin area, are likely to be designated as Must Run Reliability plant (or "constrained-on" plant). For this reason, we describe the position of constrained-on plant in section 4 of this response. In section 5, we analyse the main problems with the current proposals. Our answers to the

[11] SEM Committee, *Capacity Remuneration Mechanism: Parameters Consultation Paper*, SEM-16-073, 8 November 2016),

[12] NERA (2016b), Competition and Cost Recovery under the I-SEM Bidding Rules: A Report for Viridian, 19 December 2016.

consultation questions on CRM Parameters in section 6 reflect this analysis. Section 7 provides a summary of our answers.

As a final comment, Energia endorses the response of the Electricity Association of Ireland (EAI) to this Consultation Paper.

2. Summary of Proposals for Capacity Auctions

According to the SEM Committee's proposals in the Consultation Paper, capacity market auctions taking place in T-4 years and during the transitional period will be subject to the three following price limits:[13]

1. Horizontal Section of Demand Curve = 1.5x Net CONE = **"Auction Price Cap"**
   - NB: Demand Price at Capacity Requirement = 1x Net CONE
2. Existing plant offer cap 1 = 0.5x Net CONE = **"Existing Plant Price Cap"**
   - Applies to all "existing plant"

Any plant, for which NGFC > 0.5x Net CONE, may apply for an exemption:

3. Existing plant offer cap 2 = Net Going Forward Cost = **"NGFC"**

Under the current proposal, the SEM Committee would prescribe a restrictive list of costs that may be included within NGFC. As currently proposed, this list excludes sunk costs, some relevant avoidable costs, and makes no provision for cost items "not elsewhere specified".

3. Economic and legal imperatives in I-SEM design

3.1 Legal Framework

In considering the market design for I-SEM, the regulatory authorities/SEM Committee are bound by the extent of their powers as specified under legislation and their statutory duties.

While reference is made below to specific duties and obligations of the CER, we note that UREGNI, as the electricity regulator for Northern Ireland, has identical functions and duties as regards matters relevant to the Third Energy Package and the Single Electricity Market and that its actions as an administrative authority are subject to similar general legal principles. All references to the legal framework in this section should be read accordingly.

As most recently explained in Energia's response to the SEM Committee's Consultation Paper on Offers in the I-SEM Balancing Market (SEM-16-059)[14], a number of key legal requirements are particularly relevant to the design of I-SEM:

[13] SEM-16-073, paragraph 6.3.1, page 43.
[14] And also explained in response to the MPM Consultation (SEM-15-094); CRM Consultation 2 (SEM-15-014); and CRM Consultation 3 (SEM-16-010).

- In their decision-making, the RAs are subject to public law principles. In particular, public authorities such as the CER must act in a manner that is (1) consistent with the legal framework within which they operate and (2) reasonable. Regulatory measures must be non-discriminatory; they must also be proportionate, that is, both suitable and necessary to achieve the aim pursued and where they affect a constitutionally protected right (such as private property rights and the right to earn one's livelihood) – impairs that right as little as possible. This is reflected in the objective set for the Minister and RAs by section 9BD of the Electricity Regulation Act, 1999 in respect of the SEM that the performance of their functions should be "*transparent, accountable, proportionate, consistent and targeted only at cases where action is needed*".
- The measures adopted by the RAs must be consistent with the Third Energy Package and its objectives, namely, as regards electricity, the implementation of the internal market in electricity so as to deliver real choice for all consumers of the European Union and more cross-border trade, and achieve efficiency gains, competitive prices and a higher standard of service, and contribute to security of supply and sustainability. In this regard, a key issue to which we return in section 3.2 below is to understand that to ensure that prices are "competitive" does not mean to ensure that they are the "lowest achievable by any means". Rather, regulation should work to ensure that the prices achieved in the regulated market approximate those which might be achieved in a competitive market and thereby provide incentives for efficient investment. This is reflected also in the principal statutory objective of the RAs under section 9BC of the Electricity Regulation Act, 1999 in relation to the SEM, namely "*to protect the interests of consumers of electricity in the State and Northern Ireland supplied by authorised persons, wherever appropriate by promoting competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the Single Electricity market*" and there is no reason why the objective pursued by I-SEM should be any different.
- The measures adopted by the RAs should, consistent with Directive 2005/89/EC of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment, ensure a high level of security of electricity supply by taking the necessary measures to facilitate a stable investment climate, which measures should be non-discriminatory and not place an unreasonable burden on the market actors. They should encourage the establishment of a wholesale market framework that provides suitable price signals for generation and consumption.

- The measures adopted should be consistent with the statutory duty of the CER and the Minister to have regard to the need, among others: (i) to promote competition in the generation and supply of electricity; (ii) to secure that all reasonable demands by final customers of electricity for electricity are satisfied and (iii) to secure that licence holders are capable of financing the undertaking of the activities which they are licensed to undertake. In accordance with European State aid law, State intervention in the market should be avoided to the maximum extent possible.
- Regulatory measures, consistent with competition law including section 5 of the Competition Act 2002 to 2014 as well as Article 102 and Article 106 of the Treaty on the Functioning of the European Union, should recognise the position of market power enjoyed in electricity markets by a State-owned entity, namely the ESB. Measures which do not properly distinguish between the position of (1) undertakings, in particular public undertakings, in a position of dominance on the market and (2) others, would lead to unlawful discrimination. Similarly, measures which do not recognise the special position of public undertakings and the possible differences in their incentives and consequent market behaviour would be incompatible with Articles 102 and 106 TFEU and Article 4 of the Treaty on the European Union.

As Energia has consistently emphasised, these legal requirements apply to each and every measure that the RAs adopt or cause to be adopted in respect of I-SEM but also, importantly, to the package of regulatory measures which together will make up the I-SEM market design – including among others, bidding restrictions on the energy markets, bidding restrictions in the capacity market, the Capacity Remuneration Mechanism, DS3 System Services, Administered Scarcity Pricing, obligations in secondary contract markets, obligations in forward markets, and other Market Power Mitigation measures. Key in this respect is the requirement that these measures, *individually and taken together*, allow generators to finance their activities. This means that this whole package of regulatory measures must provide generators with an opportunity to cover their costs.

It is a very serious concern of Energia that measures proposed and/or preferred by the RAs for the design of the energy and capacity markets are together neither efficient nor optimal nor in fact a lawful combination. We have now had the opportunity to review the SEM Committee's proposals for every part of the I-SEM, i.e. the markets for capacity, energy and ancillary services ("DS3"). Although the different proposals are available in greater or lesser detail at this stage, a worrying pattern has emerged. Apparently arising from fears of potential market abuse, the designers of each part of the I-SEM are imposing tight restrictions on the costs that generators can include in their offer prices – and, in some cases, in the prices they are paid. In some cases, the designers assume that generators can adequately recover the other costs in some other part of the market, but they do so without checking the truth of that assumption. Energia does not believe that the regulatory authorities' approach complies with their statutory obligation to have due regard to the need to ensure that generators are capable of financing their licensed activities. In fact, the whole package of market designs is proving to be so restrictive that, altogether, it will deny any prospect of total cost recovery, both by disallowing specific costs in every market, and by leaving no flexibility for generators to recover these costs when an opportunity arises.

Unless the SEM Committee gives immediate consideration to this problem, and lifts or slackens some of the restrictions, the I-SEM will soon be staring disaster in the face. By denying any prospect of total cost recovery, the I-SEM will destroy any incentive to invest in keeping capacity available, or in building new capacity – *particularly within the constrained areas where capacity is most valuable to system security,* but where generators will face serious difficulties in ensuring the financing of their activities, an issue which the regulatory authorities do not consider contrary to their statutory duty to do so. As such, the market design chosen and specifically the market power mitigation measures consulted upon in both the Energy and Capacity markets imply a high risk of inefficient and inappropriate exit signals being generated contrary to steps being taken elsewhere by the RAs to ensure there is sufficient generation adequacy in areas that are considered transmission capacity constrained[15].

In taking this approach, the SEM Committee appears to be driven by the principle that measures should be favoured on the basis that they will produce *low prices*, rather than *competitive market pric*es[16]. For the reasons set out in further detail below, this approach is contrary to the RA's statutory duty to promote competition and is inconsistent with the requirement under Section 9BC(4) of the 1999 Act that measures are "*best calculated to promote efficiency and economy on the part of authorised persons*". This approach is also irreconcilable with Section 9BD of the 1999 Act which requires that the CER act in a manner that is "*transparent, accountable, proportionate, consistent and targeted only at cases where action is needed*". The measures proposed by the regulatory authorities in this consultation are neither proportionate nor targeted, in particular as regards constrained on generators, but rather extend to the entire market measures which are designed to address issues of market power arising in respect of a limited number of generators only.

[15] See CRM Locational Issues Decision Paper SEM-16-081, 8 December 2016.
[16] The purpose of price controls in capacity or energy markets is to prevent prices rising to excessive levels, or falling below predatory levels, as a result of market abuse. Given the market structure in the all-island market, it is remarkable that the risk of predatory pricing is not being explicitly addressed.

This means also that together these measures, as further explained below, produce a result that is inconsistent with the Third Energy Package and the Electricity Security of Supply Directive and contrary to the requirement that generators should be able to finance their activities and be allowed enjoyment of their property rights.

In particular, measures that are currently under consideration by the RAs, including in particular the rules regulating bids into the capacity market, restrictions on the market price, and the unjustified discriminatory treatment of existing capacity do not promote competition, do threaten security of supply and directly and significantly affect the property rights of existing generators such as Energia and their shareholders. As participation in the market designed by the RAs is the only means available to existing generators such as Energia and its shareholders to exercise their property rights and right to earn a livelihood, it is incumbent upon the RAs, and essential, that the market design respects such property rights and allows a generator to recover all its costs – any design which does not allow a generator to recover its total costs would amount to a form of unconstitutional expropriation.

3.2 Overly detailed and prescriptive regulation hampers competition and efficient outcomes

Before setting out how the proposed measures together, and the CRM Parameters measures individually, will produce an outcome that is fundamentally at variance with the principles set out above, it appears necessary to recall a number of essential features of electricity markets and I-SEM and fundamentals of welfare economics, which the proposed measures and consultation paper appear to ignore:

- First, it is worth recalling that the costs of generation comprise: (1) the investment cost of building capacity in the first place; (2) the cost of fuel used to generate electricity; (3) the associated cost of EU Emissions Allowances to cover emissions of greenhouse gases; and also (4) different types of operating and maintenance (O&M) cost. The cost of O&M derives from (a) consumables used in production, (b) recurrent repairs caused by the 'wear and tear' of running the plant, and (c) the refurbishment (servicing) required after a certain amount of operation, to prevent generator plant from breaking down.
- Uncontroversially, as explained in section 4.2 of the NERA Report[17], it is a fundamental principle of welfare economics that competitive markets allow the recovery of average total costs over the long run.
- This includes sunk costs. Sunk costs do play a role in efficient decision-making and they have a bearing on incentives. This is because the

[17] "In equilibrium, entrants in competitive markets would recover their sunk costs on average" (p 7)

regulatory treatment of sunk costs affects market participants' perception of a regulatory regime. In practice, regulation that fails to allow recovery of sunk costs from past investments will make investors reluctant to invest in the future as investors will only invest in new capacity if they are confident they will be allowed to recover their cost which, once the investment has been made, is sunk. A market design which does not offer investors in efficient generator capacity any prospect of recovering *all* these costs will destroy the incentive for efficient investment of the type needed to serve consumers' needs.

- Were electricity markets operating under "perfect competition" conditions then the price of energy would be decided by one of two rules:

  1. if available capacity were *sufficient* to meet total demand, the market price would equal the highest variable (or "short run marginal") cost of all plant running at the time in a least-cost despatch (that is the least-cost pattern of generation output);
  2. if available capacity were *insufficient* to meet total demand, the market price would rise to a "scarcity price", in order to ration available generation output by reducing demand.

  Scarcity pricing is particularly important for the design of any electricity market because such prices provide an opportunity to recover fixed costs and the incentive and reward for investing in generation capacity. Generators capture the reward by selling their output either at scarcity prices when they arise, or through long-term contracts whose prices include the anticipated value of future scarcity prices. As the incentive and reward for investing in generation capacity, scarcity pricing is crucial for achieving security of supply.

- Electricity markets, however, do not operate under "perfectly competitive" conditions so that the competitive price for energy is driven by a number of other conditions, not all of which can be captured in simple rules.

  - Demand for electricity varies widely over time and total generation output therefore has to change from minute-to-minute and hour-to-hour, to match the variation in demand. Different types of generator are suited to meeting different types of demand: some are best suited to running continuously ("baseload"), whilst others are designed to run infrequently (i.e. only when demand reaches high levels) or flexibly (i.e. when the level of demand changes quickly); the generation output must also take account of transmission constraints which effectively segment electricity markets.
  - If the market tightens temporarily, due to a sudden rise in demand and/or a shortage of (flexible) generation capacity, competing generators can then sell their output at a price above the short run

variable costs of the plants running at the time. In other words, in conditions of relative scarcity, or when sudden demands take the market by surprise, generators in competitive markets may earn high prices from being available and flexible enough to meet demand at the key moment. In these conditions, prices may be temporarily detached from the cost of production and defined instead by the cost of the buyer's alternative source of supply. (Tight markets can emerge from conditions changing at short notice even if the overall balance of supply and demand would not trigger rationing prices like the Administered Scarcity Prices. This observation is not specific to electricity markets. The same phenomenon is found in the market for any commodity whose production and delivery to the market requires advance notice.) Although uncoupled from production costs, such prices are competitive since, in a competitive market, anyone can earn these prices by investing to make plant available and flexible. Indeed, the prospect of earning such high prices is needed to attract investment in capacity and flexibility; the problem of "missing money" arises when this prospect is denied.

  - Actual or threatened restrictions may hold energy prices below the competitive level (duly taking into account scarcity pricing), in which case the market is said to suffer from "missing money".[18] "Missing money" discourages efficient investment and reduces security of supply, unless counter-active measures are taken to make up the missing revenue, such as a capacity market.
  - Just like the SEM, I-SEM will be characterised by the dominance of ESB, that is, its ability to act independently of its competitors and ultimately consumers. This justifies the imposition of targeted rules designed to address the market failures arising from that situation. It does not justify regimenting price formation and cost recovery for all operators on the market.

- In practice, the markets for capacity, energy and ancillary services ("DS3") provide the only means for investors to recover all these costs, including where these costs are "sunk".
- I-SEM will set a single, market-wide price, as if transmission constraints did not exist; higher cost ("out-of-merit") generators, that must run behind actual transmission constraints to support the system, will be paid their own offer prices for their capacity and for the energy they generate. For some generator capacity, most of its revenue – and virtually all of its margin over the variable cost of generating – will come from sales as a

[18] The I-SEM is subject to many limits on offer and market prices, including an energy price cap of €3,000/MWh due to software restrictions.

"constrained-on generator", at its own offer prices. Such a generator will only be able to recover all of its costs from sales of capacity and energy *at its own offer prices*.[19] This will be possible only if the definition of allowed costs and offer prices is flexible enough allowing to reflect the full diversity of generators and situations.

It follows from these fundamental principles that in any market, there is not one "competitive price" but a range of competitive prices. In order to allow competition and efficient outcomes, market rules must offer all market participants the opportunity to recover their total costs – including sunk costs, operating expenses and the cost of capital – in order to maintain incentives for efficient investment. This means that competitive market pricing requires flexibility to price above variable costs so that the competitive process can flourish. Ruling out such pricing would hinder the competitive process and deny generator a legitimate means to recover their costs.

Having regard to the fact that competitive markets operate in a complex manner, promoting competition means facilitating the competitive process, including by preventing overt market abuses, and it is only then indeed that efficiency can also be promoted. It is Energia's views that taken together, current proposals for the design of I-SEM reflect an intention by the SEM Committee to exercise detailed control over market outcomes with the unavoidable result that generators will be deprived of the flexibility that is required for generators to react competitively to changing conditions.

In particular throughout the various consultations, including the CRM Parameters consultation, the SEM Committee gives every impression of trying to restrict all prices to the level of generators' costs which are in turn strictly defined by the SEM Committee. The SEM Committee's view appears to be that mitigating market power requires electricity markets to be regulated on the basis of the cost-of-service. This view would explain why the SEM Committee misapplies the concept of "missing money" and discusses it in terms of *costs* (specifically, a failure by generators to recover their Net Going Forward Costs in capacity markets and/or their Short Run Marginal Costs in energy and ancillary services markets), instead of discussing any potential shortfall in *revenue* relative to a competitive market price, as should be the case.

However, as explained below, a cost-based pricing approach is neither permissible nor appropriate in the circumstances of I-SEM.

[19] Sales of ancillary services at fixed tariffs may provide another means to cover fixed costs, but cannot be relied upon. For individual generators, the volume of sales of ancillary services is highly uncertain and the whole "DS3" regime may change shortly from tariffs to one more reliant on generator bids. In any case, under the current proposals, any forecast margin earnt from selling ancillary services is deducted from the allowed costs that may be included in capacity market offer prices according to the RAs' prescriptive definition of NGFC.

3.3 The type of cost-based pricing approach followed is neither permissible nor appropriate for I-SEM Design

A duty to promote competition does not in any way allow a regulatory authority to dictate a particular outcome, including where the authority (mistakenly) believes that such an outcome is "competitive". As such, the cost-based approach being pursued by the RAs is not consistent with allowing – let alone promoting – competition as is the statutory duty of the RAs and is not a form of regulation that the RAs have the power to decide. As explained above, in a competitive market, it would be wrong to assume prices equal NGFC or SRMC at all times (even allowing for the loss of load hours when the Administered Scarcity Price applies). The purpose of price controls in CRM capacity markets is to prevent prices rising to excessive levels, or falling below predatory levels, as a result of market abuse; price controls are not intended to dictate where the competitive price should lie within that range, or to override the competitive process. Intrusive controls will hinder competition and harm incentives for efficient investment and operation of generator plant. For the success of the I-SEM, it is vitally important that the SEM Committee focus on allowing competitive market prices and does not expect capacity market prices to be tied to a restrictive definition of "net going forward costs" or to the long term average costs of new entry (i.e. net CONE).

Not only is the SEM Committee's approach incompatible with the promotion of competition and the development of competitive markets: it even fails by the standards of (cost-based) monopoly regulation, by paying no heed to sunk costs and providing a return on capital. In particular, the CRM Parameters Consultation Paper denies the need to recover the sunk costs of "existing investors",[20] as if such costs formed a special category because they were incurred before the current date. However, for investors in long-lived assets that operate under a permanent (albeit evolving) regulatory regime, there is no such thing as a special date, before which "past" costs are sunk (and can be ignored) whilst "future" costs are avoidable (and must be remunerated). Time moves forward continuously. Today's sunk costs were avoidable costs of investment in the past; today's avoidable costs of investment will become sunk costs in the future. Disallowing, or even just ignoring, sunk costs will inevitably discourage future investment.

The need to allow recovery of sunk costs is part-and-parcel of regulating energy networks. It is a pre-condition for *credible* incentives to invest in efficient, long-lived, irreversible assets. Significantly, the Energy State Aid Guidelines require that, in order for aid to be compatible, the scheme must "*not undermine investment decision on generation which preceded the*

[20] SEM Committee, *CRM Parameters Consultation Paper*, SEM-16-073, 8 November 2016, paragraph 6.3.9, page 44.

measure" (paragraph 233).[21] The necessity of recognising sunk costs does not evaporate when a regulatory regime is applied to a market instead of a monopoly. Market prices may rise or fall, but there is never any justification for a regulatory regime whose pricing rules systematically disallow sunk costs on principle. Such a regulatory regime would be inconsistent with the regulatory authorities' statutory duties to encourage efficiency, to promote competition, and to foster security of supply. A requirement on generators to submit offers in the I-SEM CRM that were below their actual Net Going Forward Costs or that denied generators the opportunity of recovering sunk costs would also be contrary to competition law, specifically Article 102 of the Treaty on the Functioning of the European Union (TFEU) and Section 5 of the Competition Act 2002 to 2014, the provisions of which prohibit predatory pricing. This particular concern arises in light of the ongoing dominance of ESB and the pre-existing concerns over the exercise of market power.

The SEM Committee's approach truly offers the worst of both worlds.

3.4 Summary

In summary, market prices may reflect short run marginal costs or scarcity prices in the ideal conditions of "perfect" markets, but the principles of competitive pricing have to adapt to a number of real-world conditions:

- Competitive market pricing requires flexibility to price above variable costs;
- Actual or threatened restrictions on prices require action to replace "missing money".
- Generators must be able to recover their costs if remunerated only at their offer prices
- The requirement to allow total cost recovery acts as a continuous constraint on regulation.

Proper recognition of these real-world conditions is lacking in the CRM Consultation Paper and in papers issued by other I-SEM workstreams. If all these proposals are put into effect as they stand, the combination will fail to offer credible incentives to invest in building or maintaining valuable generation capacity (particularly the constrained-on capacity, required to support the system). These proposals would bring about a regulatory regime whereby generators will be denied the possibility of recovering all of their costs placing in jeopardy their ability to finance their licensed activities and accordingly, their participation in I-SEM. As participation in I-SEM is the only

[21] The US obliges government agencies to provide the opportunity, at least, for investors to recover all their costs, including sunk costs of investment, operating expenses and a fair rate of return. This obligation is derived from an interpretation of constitutional property rights, but is recognised as desirable *per se*, because it works to the *public* good (not just to the benefit of investors).

way for generators to get the benefit of their property (being their generation assets), the impossibility created by the RAs for them to recover their costs would mean that the regime constitutes an unjust attack on their property rights. This is in circumstances where, as mentioned previously, the regulatory authorities have a statutory duty to have regard to the need to ensure that generators may finance their licensed activities. Any failure to ensure generators', including constrained-on generators', ability to finance activities and accordingly to invest in building or maintaining valuable generation capacity would have potentially disastrous consequences for I-SEM and ultimately consumer interests including in terms of security of supply.

4. The Position of Constrained-on Plants

Energia has many comments about the proposed limits on offer prices and auction prices for I-SEM capacity markets. Our concerns are heightened by the expectation that our own plant at Huntstown, which is a significant and reliable resource at the disposal of the TSO, is likely to be designated as Must Run Reliability plant (or "constrained-on" plant). Such plant is required to support the system, but inevitably has higher costs than in-merit plant (or else it would be in-merit itself). In the I-SEM markets for capacity and energy (and in the future perhaps for ancillary services[22]), constrained-on plant will receive the price that it bids, rather than the clearing price. The proposed limits on offer prices in all these markets would prevent these plants from earning additional market revenue (i.e. Inframarginal Rents) over and above the costs they are allowed to include in their offer prices. This situation raises two separate concerns:

- First, if the SEM Committee restricts the range of cost items eligible for inclusion in the offer price for any single market, allowed offer prices may lie below the true marginal cost of participating in that market. Such restrictive rules would destroy the incentive for efficient participation in individual markets.
- Second, if the whole panoply of proposed limits on offer and auction prices restricts the offer prices – and hence the revenues – that constrained-on generators can earn across all markets, some efficient generators may be unable to recover their total costs.[23] Such an outcome would be intolerable for the owners of the plant, and would

[22] As mentioned earlier (ibid footnote 1), the method of pricing ancillary services is of little importance in this context. Generators cannot rely on a stream of net income from sales of ancillary services, even at tariff rates, to fund investment in generation capacity. In any case, under the current proposals, any forecast margin earnt from selling ancillary services is deducted from the allowed costs that may be included in capacity market offer prices according to the RAs' prescriptive definition of NGFC.

[23] In this context, at least, the proposal to apply "Administrative Scarcity Prices" during periods of system stress is not relevant. The need to reward plant that is constrained on applies regardless of conditions on the system as a whole. Even if the whole system has a surplus of generation – and therefore no scarcity pricing – for many years to come, constrained-on generation capacity will continue to have a high value that is not represented in general market prices.

force the premature closure of existing capacity precisely where it is most needed. Consumers would have to pay for the construction of new and more expensive capacity (under the more relaxed regime for "new capacity").

The need to maintain incentives for efficient production within each market is a fundamental aspect of promoting competition, a key objective of the Third Energy Package reflected in the statutory duties and functions of the Regulatory Authorities. The observation that some of the most highly valued generation capacity in the I-SEM will be rewarded at its own offer prices means that regulatory price limits must provide the opportunity for generators to recover their total costs – including the costs of past investment needed to keep the plant available and the costs of financing that investment.

In practice, various Consultation Papers issued by the SEM Committee under different workstreams (CRM, BM, DS3) are all proposing restrictive price limits – in some cases on the assumption that the disallowed costs can be recovered in other markets, without checking whether they can be. Overall, the restrictions prevent the recovery of some costs from any market – a combination of rules would have adverse – perhaps disastrous – consequences for efficiency and for system security.

Our comments are therefore informed by the challenge of trying to finance investment and operations in existing plant whose revenues will be restricted – often to levels below actual costs - by the proposed offer limits.

5. Key Concerns and Responses

5.1 Introduction

We have explained in section 3 why, for both legal and economic reasons, it is an imperative that consistent with promoting competition and efficient outcomes including in terms of security of supply, I-SEM is designed so that generators may recover their total costs. We have also explained why this in practice requires flexibility within the market design so that generators have the incentive to compete and the competition process can flourish to the benefit of consumers. In this section we explain our key concerns in the context of the detail of the specific proposals set out in the consultation paper.

5.2 Fundamental flaws in the proposed measures will hamper cost recovery

Enabling generators the opportunity to recover their *total costs* is fundamental to security of supply and remains a key concern for Energia. The RAs' temptation to regulate the market too prescriptively should be resisted[24]. In

[24] This and other I-SEM workstreams have consistently demonstrated a desire on the part of the RAs to tightly regulate the market, with a particular focus on local market power. However, holding prices too

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 market power controls should target the State owned incumbent ESB, to mitigate the potential distortion of the capacity market resulting from its dominant position and non-commercial drivers; and
- 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").

Adopting the first of these points would reflect the analysis of capacity (and energy) markets set out in previous SEM Committee consultation papers on market power mitigation. In those papers, the SEM Committee found that ESB (and possibly one or two other generators) will possess substantial ("pivotal") market shares for many years to come.[25] However, many generators fell below the threshold for concern about market power. It is therefore surprising to find market power mitigation measures being applied to all generators without distinction, and to conditions (i.e. non-energy actions) where they do not necessarily have market power.

The second bullet point 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 reaches the New Capacity Investment Rate threshold, it would be eligible for a long term capacity contract, but in our view it will be impossible to reach the threshold as currently defined. If such investment does *not* reach the New Capacity Investment Rate threshold, 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.

low is one way to guarantee that no-one else enters the market (and existing players leave the market prematurely), which would harm consumers' interests.

[25] See for instance, SEM Committee (2015), *I-SEM Market Power Mitigation: Consultation Paper*, SEM-15-094, 20 November 2015, chapter 6.

5.3 ”Net Going Forward Costs” is an entirely unsuitable concept to define the "Existing Capacity Price Cap"

The concept of “Net Going Forward Costs” is entirely unsuitable for defining the “Existing Capacity Price Cap” and is unduly restrictive (too low) as a basis for setting offer prices. The SEM Committee is proposing to cap capacity market bids submitted by “existing” generators at 0.5 times (0.5x) Net CONE, although the cap on individual generators may be increased, on application, to their Net Going Forward Costs, as defined by the SEM Committee and equal to the sum of a restrictive list of costs, which the SEM Committee might further reduce by its estimates of “efficiency savings” based on *assumed* efficiency improvements. In Consultation Papers produced in other workstreams, the SEM Committee is also proposing to tie market prices for energy to a restrictive definition of Short Run Marginal Costs.

Together, these rules would produce a potentially disastrous combination; in which restrictive-regulation gave the generators required for system security no prospect of recovering their total costs. (Other generators may also quickly find themselves in the same position.)

The treatment of fixed operating costs provides an example of how inconsistent price limits deny cost recovery. In defining NGFC, the SEM Committee observes that “it is likely that the NFOC contains a proportion of Variable Operating & Maintenance (VOM) costs *which can be recovered via the energy or ancillary service markets*”[26] (italics added). This statement merely reflects the established position under the SEM and the BCOP. However, the SEM Committee has issued another Consultation Paper on offer price controls in the Balancing Market which explicitly states that *“maintenance costs are not considered variable in nature and are therefore not considered by SEM Committee as eligible cost items for inclusion in offers”*. These two statements are inconsistent. Together they deny generators any chance to include VOM costs in their offer prices, or (for constrained-on plant) to recover their VOM costs. A totally different approach – and closer coordination between workstreams – is required to avoid such outcomes.

Offering generators the prospect of earning a return on investment, in addition to short-run operating costs, is 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

[26] SEM-16-073, paragraph 6.3.23.

irreversibly. To ensure system security, consumers would then have to pay for long term contracts with costly new plant – an inefficient outcome.

5.4 All generators should have the same opportunity to recover total costs

A competitive and sustainable market must offer generators the prospect of recovering their total costs over the long run. In this respect, there is no distinction between new and existing generators since, over the long run, today's new generators are tomorrow's existing generators, for the reasons given in section 5.4. (In the absence of any relevant distinction, the treatment of new capacity is discriminatory and may cause the inefficient closure of generating assets required for system security.)

New entrants will be able to access long term contracts under the SEM Committee's current proposals. In the year following the award of an RO, a new entrant will no longer participate in the capacity market, and the remainder of the market is likely to be in surplus. In the year in which entry occurs, prices will only rise to the net CONE of that particular new entrant (spread over a 10-year contract), but they will remain below that level during times of surplus, until new entry is required again. That is quite different from the current system, in which shortages or surpluses can drive the price per unit of capacity above as well as below Net CONE (spread over a 20-year project life in the BNE process). Over the long run, the incentive in the new system to maintain and operate existing capacity will remain systematically below the incentive for new capacity and would deny recovery of sunk costs at least for some plants. The marginal plant in any capacity auction falls into this category, but so too do generators that are required for system security and that are constrained on in the capacity market.

Restricting the length of contracts available to existing capacity to one year, whilst linking the price of such contracts to prices in longer term contracts, artificially limits the ability of investors to recover their sunk costs. The capacity market must therefore offer some alternative provision for total cost recovery, or else it will stifle competitive price signals. ***In practice, this alternative must take the form of allowing some flexibility for existing capacity to bid prices above their own recurrent costs.***

Energia finds that there is no sound basis for distinguishing between the treatment of existing and new capacity: both are capacity, and existing capacity was new capacity when it was built. To the extent that rules are devised that distinguish between them, it is imperative that such rules do not produce discriminatory outcomes or rely on discriminatory principles, are consistent with the statutory duties of the RAs, and have due regard to the requirement that existing capacity must be capable of being financed throughout its lifetime, regardless of when it was built. This means that the rules should ensure that existing capacity is able to recover all of its costs and is not restricted to recovering only recurrent costs.

The RAs appear to believe that the CRM will involve State aid. We note that the Energy State Aid Guidelines require that in order for aid to be compatible, the scheme must "*improve the functioning of a secure, affordable and sustainable energy market*" (paragraph 49) and "*not undermine investment decision on generation which preceded the measure*" (paragraph 233). A measure which denies overall cost recovery to existing capacity and restricts existing capacity to only recovering recurrent costs is inconsistent with both these requirements and discriminates without valid justification between existing and new capacity.

5.5 Mitigating market abuse means letting competition flourish, to ensure security of supply

Regulating competitive markets by reference to costs is not efficient, practical or in consumers' interests, as it would eliminate the benefits of competition whilst offering none of the benefits of monopoly regulation. Instead, the SEM Committee should ensure that any attempt to prevent abuses still gives the competitive process room to flourish, so that generators have the flexibility to recover their costs where and when the market allows.

Energia would like to emphasise strongly that:

(1) Commercially motivated generators already have an incentive to maximise profits and hence to minimise costs, despite the suggestion in the Consultation Paper that costs may not have been efficiently incurred by generators in the SEM because the CPM insulates them from competitive pressures. The observation that FOM costs within the SEM differ from international benchmarks provides no evidence on relative efficiency;

(2) An attack on cost recovery will quickly threaten security of supply by forcing the closure of independent generators, which will only undermine competition further, by reinforcing the dominance of the State-owned incumbent ESB, both structurally and at a local level; and

(3) Any attempt to deny existing generators the opportunity to recover their total costs (including sunk costs and return on capital) is incompatible with the statutory duties of the RAs and constitutional protection of property rights and would be susceptible to challenge. It would heighten the perception of regulatory risk and seriously undermine the incentives for future investment in this market, undermining security of supply and increasing long term costs for consumers.

The Consultation Paper repeatedly points to the current Grid Code requirement to give 3 years' notice of plant closure as a reason to expect the

Capacity Requirement to be met during the transitional period[27]. However, for reasons set out in our response to the Locational Issues Consultation (SEM-16-052), the SEM Committee may not lawfully maintain such a notice period for which no justification has been provided in circumstances where it conflicts with the objectives being pursued with the I-SEM design, including in particular ensuring that appropriate entry and exit signals are given to generators. Even if such a requirement was maintained, then it is the duty of the SEM Committee to ensure that the provision of capacity available as a result of the three years' notice requirement is remunerated adequately in accordance with the statutory duty of the RAs to ensure that licensed generators can finance their activities. A prohibition on exit where the regulatory regime is not calculated to ensure that generators required to maintain capacity available during a notice period are adequately remunerated, as the SEM Committee’s proposals imply, would be entirely unjustifiable, unreasonable and disproportionate and constitute an unjust attack on the constitutionally protected generators' property rights. Furthermore, and in any event, it would be futile (not to mention falsely reassuring) to rely on Grid Code requirements to keep plant open for system security reasons, if cost recovery is not also assured.

Perversely it is the very plant most needed for system security (for locational reasons) that are being explicitly prevented from recovering their costs under the SEM Committee’s current proposals for mitigating market power in the I-SEM energy and capacity markets. This would have a significant bearing on the economic welfare and financial situation of the generators concerned who would likely challenge such proposals, on the basis of the legal principles set out in section 3 above.

5.6 Security Standards

Any potential threat to cost recovery affects incentives to build and maintain generation capacity, and hence puts security of supply at risk. The SEM Committee is compounding this problem, by using an arbitrary and inconsistent re-definition of security standards, for which no reasons or justification has been provided, to lower capacity market price caps.

In calculating Net CONE, the SEM Committee is proposing to assume that the BM price will rise to “Partial ASP” in four hours of positive LOLP, in addition to the eight hours of lost load (LOLH). This assumption would inflate the forecast of Inframarginal Rent (IMR) and depress the value of Net CONE. However, adding this element to the calculation of the Net CONE is inconsistent with both current security standards and capacity requirements.

There is no justification for arbitrarily assuming that there are four hours per year when LOLP is positive, on top of the eight hours of lost load. The

[27] See paragraphs 4.5.8; 5.3.23; 6.3.14; and 6.4.19.

security standard for the Irish electricity market is defined as eight LOLH per year. Some of the eight LOLH are already represented by hours of “partial ASP”, when load is not lost, but when the probability of lost load is high enough to affect the perceived risk of losing load and hence the value of electricity. The security standard amalgamates hours of positive LOLP into the equivalent of eight hours of lost load. The security standard of eight LOLH therefore already incorporates all the hours of “partial ASP” that the SEM Committee wishes to add.

Adding any hours of “Partial ASP” implies both higher generator revenues and a lower security standard than at present, which is only a sustainable equilibrium if new capacity is more expensive than previously thought. Adopting those assumptions would require the SEM Committee also to adopt (1) a different capacity requirement and (2) a different demand curve in the capacity market. The SEM Committee cannot therefore assume additional hours of LOLP on the supply side without making an equivalent adjustment on the demand side. This in turn would require a proper analysis of system security standards, which the SEM Committee has not carried out. Just adding hours of “partial ASP” to the calculation of Net CONE is an arbitrary and unacceptable decision, which would be made without any justification.

Furthermore, when discussing price caps, the SEM Committee assumes that the market will have excess capacity for some years to come. In such circumstances, it is unrealistic to assume that the market will be tight in any periods.

The SEM Committee therefore has no basis for arbitrarily assuming a tighter market that would produce higher prices and a lower Net CONE.

5.7 Incentives

The SEM Committee’s approach is to list the specific cost items that generators will be allowed to include in capacity market offer prices. The list of allowed cost items is inevitably incomplete, and will deny bidders the opportunity to recover all the incremental costs of making a plant available, let alone any past costs incurred for that purpose. If RO prices do not cover all the incremental costs of making generation available, they will eliminate all incentive to provide capacity.

We can see already that the SEM Committee’s proposal omits the following categories of costs:

- Costs of any prospective investment (which may or may not allow admission as a new build generator under the capacity market rules);
- Costs of past investment, including recent investment required to keep plant available;

- Expected costs of holding an RO other than difference payments, such as termination fees or any other penalties that may be imposed under the RO (with a probability greater than zero); and
- Costs of risk or working capital to deal with variations in earnings.

However, even expanding the list of allowed cost to include these items would not be sufficient, as we do not believe that we can anticipate every type of cost that we and other generators will incur in the coming years. The proposed approach can only work and be acceptable if there is some provision for including “costs not elsewhere specified”.

The treatment of investment costs throws into high relief the practical difficulty of applying the SEM Committee’s proposed approach. So-called “existing” generators cannot remain available indefinitely without occasional expenditure on refurbishment and repairs. This expenditure is normally incurred in one year and amortised over the following 5-10 years (or longer), depending on the period between repairs (and/or other accounting conventions). We recognise that the SEM Committee intends that all generators may apply for a higher offer price limit in some circumstances. However, under the proposal to limit bids to NGFC, existing generators will not be allowed to include these costs in capacity market bids for any year except the year of the expenditure:

- before they are incurred, investment costs are “out-of-period” (i.e. not attributable to the year of the capacity market);
- after they are incurred, they will be disallowed as “sunk costs”.

The inability to recover such costs would force existing plants to withdraw from the capacity market, i.e. to close prematurely. New plants would be built (on the promise of a long term contract), even though that is unlikely to be the least-cost or most efficient outcome.

This problem will be particularly serious for Reliability Must Run plants, i.e. plants needed for reasons of system security. Rules that prevent long term cost recovery will lead to the closure of plants whose capacity has a particularly high value to consumers. Replacing them will new plant in similar locations will raise costs to consumers.

Incidentally, the value of constrained-on plant is only defined in part by the cost of keeping it available; the competitive market price of such plant is often defined by the cost of alternative measures to achieve the same level of security. Constrained-on generators cannot demand a price higher that the cost of those alternatives, e.g. the price of other generators able to offer an equivalent service (as in the case of Huntstown and Poolbeg) or the cost of investment in the transmission network. If their offer price exceeds these levels, they will simply price themselves out of the market.

5.8 Summary

Preventing market abuse does not require a rule that defines precisely which of their costs ("NGFC") generators may include in their offer prices and, ultimately, in the prices they receive for their capacity. The SEM Committee cannot rely on "international best practice" to justify this approach, since there is no system in the world that aims (or could ever aim) to foster competition and security of supply with the combination of measures currently proposed for the I-SEM's markets in capacity and energy (and, in future perhaps, ancillary services). On the contrary, it will be essential to allow much greater flexibility for the competitive process to work – occasionally allowing generators to bid more than NGFC, because of the necessity of recovering sunk costs. This provision may be defined by allowing for "any other costs not elsewhere specified", or better still by focusing the scrutiny of offer prices on particular cases of suspected abuse, and allowing the competitive process to dictate market pricing whenever possible. *Ex post* regulation of this type has been effective under the BCOP in the SEM, and represents normal practice in other electricity markets. There are no grounds for adopting a different approach for the I-SEM.

The SEM Committee's own consultations have shown the risk inherent in trying to impose detailed and inflexible *ex ante* regulation on complex and evolving competitive markets. It is already apparent that (1) the proposed approach is not practical, (2) if implemented, it will not be stable, it will generate inefficient outcomes and it will hinder competition and threaten security of supply. The only possible conclusion is that a different approach is required to meet the SEM Committee's usual I-SEM assessment criteria, and to comply with the regulatory authorities' statutory duties.

6. List of Consultation Questions

Below we set out our response to the questions in the Consultation Paper.

Section 2 – Administrative Scarcity Pricing Parameters

2.31 The SEM Committee welcomes views on all aspects of this section, including whether you prefer Option 1 (as set out in Section 2.2 above), Option 2 or some intermediate option for the shape and slope of the ASP function, and why?

Option 1 is preferred, at least for a transitional period, given the considerable uncertainty that exists with respect to the functioning of the I-SEM energy trading arrangements in practice, especially given the lack of quantitative analysis or testing during the detailed design phase. As ESP Consulting have noted in their Stocktake of the I-SEM Programme:

- …"it is normal to be cautious in introducing markets. It is common practice to have transitional measures…" (p21)
- "ESP Consulting believes it prudent to: …consider whether transitional measures are required to manage the risks discussed above as the I-SEM is introduced" (p22)

In light of the above and the prudent philosophy advocated by the RAs' own advisors, Energia strongly recommends a cautious approach to setting the ASP function.

Prices under Option 2 would be universally higher than under Option 1, which means that we would expect consumers to pay more for their energy. The theoretical offsetting benefit to consumers of paying higher prices is that, all else equal, it increases the incentive for investment (albeit locationally blind) and contributes towards ensuring the efficient level of security of supply. However, in practice, there is a danger that Option 2 could impose net costs on consumers without providing the offsetting benefit. This is because Option 2 imposes substantially greater financial risks on market participants, which, given the concerns raised by independent experts regarding the proper functioning of the I-SEM intra-day energy and secondary capacity markets[28], could undermine cost recovery and therefore security of supply.

Option 1 should therefore be implemented, at least on a transitional basis, until operational experience confirms the proper functioning of intra-day energy and secondary capacity markets. This will ensure consumers receive the stated benefits of the higher energy pricing being administratively imposed by the SEM Committee.

[28] The risk of dysfunctional intra-day energy and secondary capacity markets is a result of structural issues, market power issues and design decisions. These issues have been validated by independent third party experts such as Poyry and NERA and were raised by Energia as part of the I-SEM stocktake exercise.

Having said all of the above, it is somewhat surprising and disconcerting to observe that Option 2 seems to be an assumed outcome of this consultation process by reference to the proposed drafting of the T&SC which states that "At the request of the Regulatory Authorities, the Market Operator shall prepare and submit to the Regulatory Authorities for approval a proposed Reserve Scarcity Price Curve based on the product of Full Administered Scarcity Price (PFAS) and Loss of Load Probability (LOLP) as a function of the Short Term Reserve Quantity" (SEM-16-075, p.105, para 4.3.1). This gives the impression that Option 2 may be a fait accompli, which would be very disappointing to say the least given the importance of due process and consultation for more informed and hence better decision making.

Irrespective of which option is ultimately chosen, the SEM Committee must ensure its consistent application where it interacts with or influences other CRM Parameters.

Section 3 – Cost Recovery and Charging

3.4.1 The SEM Committee welcomes views on all aspects of this section, including:

A. Which of Options 1 to 3, as set out in Section 3.2, do you think is most appropriate, and why? Alternatively, what other definition of the Supplier Charging Base would you chose and why?

Energia supports Option 3, the 'minded to' position of the SEM Committee.

The purpose of targeting the supplier charge is to provide incentives to the demand side of the market to modify its consumption behaviour. If the results of the historic analysis however are inconclusive, and it is not clear which trading periods the tariff incentives should be targeted at, then there is no sound economic basis for implementing a highly targeted tariff.

A further consideration is the distribution of capacity charges across customer types. The analysis presented in the consultation paper demonstrates that residential customers would pay proportionally more of the capacity charge under a more targeted regime. It is difficult however for residential customers to alter demand consumption during peak times, as residential consumption patterns are closely linked to basic human requirements, such as provision of heat and light, particularly in winter months. Therefore targeting supplier capacity charges solely at peak time periods is likely to be an ineffectual signal that increases the financial burden on domestic customers, if non-domestic demand migrates to other times during the day to avoid the charge.[29] Such an approach could risk increasing fuel poverty, while

[29] As the charge would be spread across fewer time periods and therefore less consumption the incentive for people who can easily move demand to do so would be greater, leaving those who cannot change consumption patterns having to fund a greater proportion of the supplier charge.

achieving very little material change in the consumption patterns of residential demand.

For the reasons outlined above Energia therefore agree with the SEMC's more balanced approach of spreading the charge across day-time periods more generally – i.e. 7am to 11pm annually. Such an approach creates a clear incentive to switch consumption from day-time periods to night time periods, when the largest and most consistent differential in consumption patterns exists.

B. Which LIBOR (or other such reference rate) should be used as the BIR, and what the values of the SPR and DPR should be?

The 12 month LIBOR rate should be considered for the socialisation fund balances as this is the longest term rate provided and this will be a rolling fund. If the LIBOR is negative, its value for the purpose of setting SPR and DPR should be set to zero.

The SPR and the DPR premiums should have the same values so the fund is cash neutral. The average bank interest rate could be considered for this fund.

Section 4 – Reliability Option Parameters

4.6.1 The SEM Committee welcomes views on all aspects of this section, including:

A. Do you agree with the SEM Committee's proposed approach to set the DSU floor price at €500/MWh?

In our view, the DSU floor price should be set to cover the prevailing cost of all existing demand side units.

B. On the assumption that the gas index will be a reference price related to gas obtained from the GB system, do you agree with the carbon intensity factor? Do you have another comments on the approach to setting the gas or oil carbon intensity factors?

The carbon intensity factor for gas (subject to the assumption that the gas index will be related to gas sourced from the GB system) is published on the EPA.ie website each year and should be aligned to that. However consulting on CIG and CIO is rather meaningless without also consulting on the reference fuel index proposed. In this regard, Energia firmly maintains, for all the sound reasons articulated in response to CRM Consultation 3 (SEM-16-010) that the RO Strike Price should be updated *daily*. Using a monthly index unnecessarily increases "scheduling risk", because within a month the fuel price which dictates the short run marginal cost of a generator may rise above the level used to set the RO Strike Price at the start of the month. Having made this point, when it comes to choice of index, we strongly suggest that the RAs should check that the index closely reflects the price at which a generator might actually buy fuel trading in the market. The RAs should not rely on the CRM Delivery Body for this insight and experience, but should rather seek expert input from companies actively trading in the market, as well as independent third party consultancies with relevant expertise. It is stated in para 6.2.50 of CRM3 Decision Paper (SEM-16-039) that the choice of indices "...should be judged by appropriately qualified experts to be a reasonable indicator of prices that can be accessed by traders in the market". Energia would suggest that this is only achievable by actually consulting with market participants on the appropriate choice of fuel indices.

C. Do you agree with the approach to setting transport adders set out in section4.4?

Again, this question is rather meaningless without also consulting on the reference fuel index proposed. Our views in respect of this are provided in response to the previous question.

D. Do you that the Billing Period Stop-Loss Limit should be set to 0.5 times the Annual Stop-Loss Limit (i.e. 0.75 times the Annual Option fee)?

The SEM Committee's proposal fails to provide incentives or limit risk and is therefore disproportionate

We do not agree that the Billing Period Stop-Loss Limit should be set at 0.5 times the Annual Stop-Loss Limit. This proposed limit would undermine one of the principal purposes of the CRM: to provide a more stable, and therefore credible, price signal to attract investment.

In CRM Decision 2 (SEM-16-022), the SEM Committee stated that in setting a Stop-Loss limit, it was making a trade-off between providing incentives to make capacity available and limiting providers' risk:

> "In selecting a limit, there is a balance between providing an incentive for performance and placing excessive risk on capacity providers. In choosing a balance between annual and shorter limits there is a balance between maintaining the performance incentive while ensuring that a single incident or short series of incidents does not place excessive risk on a provider. Ultimately, placing too much risk on providers may discourage investment in plant and reduce competition or frustrate the purpose of the CRM."[30]

This reasoning however is misguided. In practice, incentives to generate for market participants are not materially different, whether or not they hold an RO, or whether or not the Stop-Loss has been reached:

- With an RO in place before the Stop-Loss limit has been reached, the market participant *earns* the strike price (P_s) if he generates and *loses* the

[30] CRM Decision Paper 2 (SEM-16-022), para 4.5.6.

difference between the market price and the strike price if he does not (P_M-P_S). The incentive to generate is the market price (P_S+P_M-P_S=P_M); and

- Without an RO in place (or once the Stop-Loss has been exhausted) the market participant earns the market price (P_M) by generating.

As a result, the impact on *incentives* provides no basis for setting Stop-Loss Limits for the capacity market.

However, setting a Billing Period Stop-Loss Limit of 0.75 times the capacity revenue will expose market participants to excessive and disproportionate risk: under the SEM Committee's proposals, a generator could feasibly lose its entire capacity market revenue or more from a single outage or pair of outages. Any generator, no matter how well maintained, could be subject to forced outage at some point of the year, but under the proposed stop loss limits, if such failure happened to coincide with a period of scarcity, the generator could be subject to a financial penalty significantly in excess of its capacity receipts. This risk increases significantly as the level of full ASP is increased. Such arrangements therefore seriously undermine revenue stability under the CRM, imposing substantial financial risk on participants, and will discourage investment, undermining security of supply.

Compare this with Stop Loss Limits in GB, where it is recognised that there is a need to ensure that market participants do not lose their entire capacity market revenues over the course of a single short outage in order to preserve incentives[31] and manage risk.[32] Generators in GB do not have to repay their capacity payment until they had failed to generate in 24 hours of stress events spread across five or more months and never have to repay more than their capacity payment for failure to deliver. The SEM Committee's proposal could require generators to repay 150 per cent of their capacity payments in less than two weeks.

Implementing a lower Billing Period Stop-Loss Limit in I-SEM would ensure that losses in excess of capacity revenues are targeted at persistent unreliable generators, reducing the risk to a market participant which is typically reliable of losing more than its entire year's capacity payment due to an unfortunately timed, but nevertheless rare outage. Such generators should obviously be penalised if not available during a stress event but the debate here is over the level of penalty for a one-time offence. Given the level of the

[31] Under the GB mechanism incentives under the capacity are delivered by means of defined penalties not the energy market price. The I-SEM scheme relies solely upon the energy market price and as explained earlier in this section the incentives provided by the energy market price remain the same regardless of whether the generator holds an RO or whether the stop loss has been reached.

[32] As DECC described it in its 2013 Consultation on the design of penalties in the Capacity Market: "The penalty cap formulation has been designed to ensure that providers will have continued incentives to deliver at future times of system stress even if they have performed poorly historically." DECC (2013), *Electricity Market Reform: Consultation on Proposals for Implementation*, October 2013, para 504.

costs involved; which are set to increase as the level of full ASP is increased; it would be detrimental to security of supply to allow a single incident to result in an otherwise reliable generator losing more than it receives in capacity revenues due to an unfortunate but rare event.

Detrimental Impacts on Working Capital Requirements and Competition

High billing period stop loss limits will require generators to hold substantial cash reserves to cover exposure to potential difference payment obligations. This has substantial cash flow and working capital implications for generation companies, increasing participation costs, and is likely to act as a barrier to new entry.

Its negative impact on competition should also be carefully considered in the context of the substantial portfolio benefits conferred upon the dominant generation company, ESB, under the CRM. The exposure faced by ESB in relation to any one of its generating units participating in the CRM is substantially offset by the large volume of capacity within its generation portfolio that, due to the de-rating process, will not be subject to the obligation to make difference payments[33].

Proposed Alternative Billing Period Stop Loss Limit

For the above reasons, we strongly favour a lower Billing Period Stop-Loss Limit and propose that this should be set at 0.125 x the Annual Stop Loss Limit. This we understand is consistent with the SEM Committee's initial thinking on the Billing Period Stop Loss Limit when it was understood then that the Billing Period for capacity was likely to be monthly as per SEM. The proposed multiplier of 0.125 is consistent with the original intent of the SEM Committee as it represents a monthly limit of 0.5 spread across 4 weeks (i.e. 0.5 divided by 4, assuming c4 weeks per month). This would help ensure that losses in excess of capacity revenues are targeted at persistent unreliable generators reducing the risk of a market participant which is typically reliable losing more than its entire year's capacity payment due to an unfortunately timed, but nevertheless rare outage. However it still maintains substantial penalties on generators if not available during a stress event.

[33] The views expressed by ESB in response to the CPM Medium Term Review are consistent with the above reasoning. Specifically, questions were raised within consultation paper SEM-11-019 on whether to increase the ex-post capacity payments allocation and to increase the Flattening Power Factor (FPF). The effect of both would have been to increase capacity prices at times of lowest margin and would only have served to increase the lottery effect of capacity payments to all parties other than those with a significant portfolio of plant. ESB was the only generation company in the all-island market to support these proposals.

Section 5 – New Build, Termination Fees & Performance Bonds

5.4.1 The SEM Committee welcomes respondents' views on the issues raised in this section. In particular, the SEM Committee welcomes respondents' views on whether:

A. You agree with the approach of setting the New Capacity Investment Rate Threshold at around 50% of the gross investment cost of the BNE plant, currently estimated at €310/kW? If not, what is an appropriate maximum size of termination fee for new capacity which achieves an appropriate balance between protecting consumers by the failure of new capacity to deliver, and not providing a barrier to entry for new capacity?

The proposed New Capacity Investment Rate Threshold is demonstrably unattainable for refurbishment. A second lower threshold *no greater than 10%* of the gross investment cost of the BNE plant should therefore be introduced, along with provision for exceptions below this threshold on a case-by-case basis.

CRM Decision 2 stated that there would be no explicit distinction between new investment and refurbishment and indicated that one threshold would cover "plant requiring significant investment"[34]. However, by setting the threshold at 50% of the gross investment cost of the BNE plant, some refurbishments to plant will be excluded by default and the threshold therefore only caters for New Build. This does not facilitate investment in plant refurbishments that may be necessary to maintain availability, enhance flexibility, improve efficiency and reliability, or reduce emissions for example. This further exasperates the fundamental problem of capping bids at Net Going Forward Costs and thus disallowing the recovery of sunk costs. This issue is discussed further in response to question 6.6.3 below.

B. You think that the SEM Committee's indicative schedule of termination fees set out in paragraph 5.3 is appropriate? Please provide evidence for your answer.

We assume the schedule of termination fees set out in paragraph 5.3 of the Consultation Paper is proposed for New Build only. It is important that New Build capacity should bear appropriate termination fees for failure to deliver projects, as a deterrent to capacity hoarding. It should be noted however that the main reason for delay on project development in Ireland has been due to non-delivery of electrical or gas connection infrastructure. Developers would therefore need to be protected for delays outside of their control before termination fees crystallise or Bonds/LOCs are called.

[34] See SEM-16-022, para 5.2.26, pages 74-75.

C. It is appropriate to place termination fees on capacity that does meet the definition of New Build, and if so, at what level, including:

- **a. Minor refurbishment or other upgrades to capacity which does not meet the financial threshold to qualify as New Build;**
- **b. Unproven DSUs;**
- **c. Any other capacity provider which has not already demonstrated its ability to physically deliver;**
- **d. All existing capacity**

We assume there is a typographical error in the question and it should read "that does *not* meet the definition of New Build." [emphasis added]

The purpose of the termination fee is to ensure that New Build capacity bids with the intention of delivering, has an incentive to deliver (has "skin in the game") and compensates consumers for any delay or non-delivery.[35] Existing capacity should not bear termination fees under any circumstances because this plant is already built and has lower incentives for non-delivery, for example by having to post collateral against difference payments and being exposed to losing this collateral under Administered Scarcity Pricing conditions, and faces obligations that New Build capacity does not.

The SEM Committee's proposals to control market power in the capacity market include limits on offers and prices. Any offer price limit must cover the expected costs of termination fees, or else it would deny cost recovery

D. .Performance Bonds should be required for 100% of termination fees, and should this vary by type of capacity?

This question does not distinguish between New Build and other capacity and therefore it is important to clarify that Energia does not agree with termination fees or performance bonds for existing capacity under any circumstances. Such penalties are neither required nor justified.

Performance bonds for 100% of termination fees (*providing that termination fees are set at a reasonable level*) is a natural follow on to provide assurance that termination fees will be paid by failed New Build projects and there would seem no reason to vary the calculation methodology for performance bonds by capacity type.

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[35] CRM Parameters Paper, para 5.3.18.

Section 6 – Auction Parameters

Net CONE

6.6.1 Do you agree with the proposed adjustments to the BNE calculation approach set out in section 6.2.8 to 6.2.10? If not, explain why.

No. Energia has two main concerns in respect of the BNE calculation:

(1) The underlying BNE value against which adjustments are made for I-SEM is significantly understated as a result of previous inaccurate and unjustifiable assumptions in the calculation, including, inter alia, setting the WACC on the basis that the BNE investor will be an investment grade vertically integrated utility[36]; and

(2) The proposed adjustments to the BNE calculation for deriving Net CONE for the I-SEM capacity market are inadequate, unrealistic and arbitrary in many important respects that will have to be addressed in the final calculation.

This response will focus on category (2) concerns but those relating to category (1) must also be addressed in a full bottom-up re-calculation of Net CONE for I-SEM.

The importance of Net CONE demands more consistent assumptions

The BNE calculation serves two different purposes under the SEM Committee's proposed design, and we consider each separately below.

The SEM Committee relies on its estimate of Net CONE to define the demand curve.

Under the proposed Options A, B and C, the SEM Committee sets the price cap for the auction at 1.5x Net CONE. At the Target Capacity, the demand curve drops to Net CONE. Thereafter, the demand curve slopes downward until capacity prices fall to zero at the point when the reserve margin above target capacity reaches 10 or 20 per cent, depending on the Option chosen.

In setting the demand curve, the SEM Committee is seeking to ensure that it attracts efficient investment in capacity in equilibrium conditions, i.e. to ensure that a new generator could enter given an expected 8 hours of lost load.

However, the risks of under or over-estimating Net CONE are asymmetric. If the SEM Committee overestimates Net CONE, the error will not constrain prices, as new entrant generators will compete the capacity price down to the

[36] This unfairly precludes entities with a lower credit rating from investing because the resulting WACC derived from the assumption is uneconomic for potential investment from entities with a lower credit rating (and therefore higher WACC) which otherwise would have been considered to be likely investors in BNE peaking plant and potentially threatens investments already made in the SEM. For a full account, including substantial evidence, of these and other concerns relating to the underlying BNE value and calculation, see Energia response to SEM-15-032, submitted to the SEMC on 22 June 2015.

actual level of Net CONE. On the other hand, underestimating Net CONE would discourage efficient investment and threaten security of supply, which would have many adverse effects. Specifically, the consequences of underestimating Net CONE for the demand curve are:

- **Setting the auction price cap too low:** Underestimating Net CONE would lower the auction price cap. If the SEM Committee underestimated Net CONE by more than one third, the price cap in the capacity market would remain systematically below the true underlying Net CONE. In such circumstances, the auction would fail to attract any new entrant capacity required to meet the SEM Committee's security standard of 8 Loss of Load Hours ("LoLH").
- **Mitigating Market Power:** The SEM Committee argued in CRM Decision 3 that a sloping demand curve had advantages over a vertical capacity target, as a method of mitigating market power and reducing the ability of market participants to raise prices by withdrawing capacity. Those potential advantages will be negated, if the estimate of Net CONE is so low that prices repeatedly clear in the vertical portion of the auction demand curve.[37]

The SEM Committee must adopt a method of calculating Net CONE that rules out the possibility of CRM auction prices being capped by mistake below the true cost of making plant available, by building in a suitable margin for error.

The SEM Committee relies on Net CONE as the basis for the proposed Price Taker Offer Limit for the capacity market.

Under the SEM Committee's proposals, "existing" plants will be unable to bid more than 0.5 times Net CONE, unless they apply for–and are awarded–an exemption because their NGFC lies above that level. Due to inconsistences between the BNE calculation and the auction rules, this cap affects the bidding of all generators, both existing and new.

The proposed CRM would offer new generators a contract for up to 10 years. However, most generators plants are expected to last for longer than 10 years – indeed, the BNE calculation itself assumes that the plant operates for 20 years. "New" generators can anticipate being treated as "existing" generators after the end of their 10-year contract. Faced with a potential price cap of 0.5 x Net Cone, they will need to recover their investment costs over the life of the contract. This rather accelerated process of cost recovery will significantly increase bids from new generators, while (and because) the price cap depresses the prices awarded to existing generators. Trying to maintain this segmented capacity market therefore has perverse effects, as well as being

[37] In terms of Figure 10 in the Consultation Paper, a lower *estimate* of Net CONE makes any given supply curve of capacity (based on *actual* costs) more likely to intersect with the vertical section of demand curve between points X and Z.

discriminatory, because the need to recover costs over 10 years or less will increase the prices paid to new capacity for their RO contracts. The prices paid to existing capacity may match the price for new capacity in years when new capacity is commissioned. However, in all other years, when the market has a surplus of capacity, the price paid to existing capacity will be depressed below the price awarded to new capacity. To avoid accusations of discrimination, investors providing equivalent capacity should all be rewarded at the same price, whether that price is defined by the cost of existing capacity, the net cost of new entry, or the demand curve.

The SEM Committee should therefore adopt a consistent set of assumptions (on plant life in particular) both when defining contract lengths for new generators and when calculating Net CONE. The SEM Committee should also offer equivalent contract arrangements, and apply equivalent pricing rules to all capacity.

The BNE WACC assumption needs to be updated to reflect increased risks under I-SEM trading arrangements

As discussed earlier, the assumption related to the WACC in the base BNE calculation – i.e. that an investor will be an investment grade vertically integrated utility – is inaccurate, unjustified and discriminatory. These deficiencies need to be addressed and the WACC updated in the context of I-SEM where the year-on-year I-SEM capacity price will be a great deal more variable (by design) than the current capacity payment, increasing risk and raising the applicable cost of capital. Furthermore, the wider market arrangements also increase the risk of participating in the market.

The calculation of IMR should use plausible forecasts, not arbitrary assumptions

The SEM Committee has predicated the design of the I-SEM on the assumption that capacity should be sufficient to meet a security standard of 8 LoLH per year on average. The calculation of Net CONE includes a deduction for the Inframarginal Rent (IMR) that generators earn in markets for energy and ancillary services. In paragraph 6.2.10, the SEM Committee merely observes that the net value of IMR at times of system stress depends on the RO Strike Price, given here as €500/MWh, rather than the applicable BM price or the ASP. Subject to the need to update the RO Strike Price to the actual figure at each auction (and hence IMR and the Net CONE), this aspect of the proposal is uncontroversial.

In paragraph 6.2.12, however, the SEM Committee proposes to add four hours of "Partial ASP", representing hours of positive LOLP, in which load is not actually lost. The inclusion of these four hours of Partial ASP has a significant effect; it increases the forecast of IMR and depresses Net CONE by the same amount. However, this adjustment to Net CONE is unjustified and the SEM Committee even acknowledges, in paragraph 4.5.8 of the same Consultation Paper, that this assumption is unlikely to be accurate at the start of the I-SEM.

The assumption of "Partial ASP" hours rewrites the security standard

The security standard for the Irish electricity market is defined as eight LOLH. In practice that does not mean that load is actually lost for eight hours each year. The number of LOLH is lower than eight in some years, and higher in others. Some of the eight LOLH are therefore already represented by hours of "partial ASP", when load is not lost, but when the probability of lost load is high enough to affect the perceived risk of losing load and hence the value of electricity. The security standard amalgamates many hours of positive LOLP into the eight hours of lost load. Thus, the security standard of eight LOLH already incorporates all the hours of "partial ASP" that the SEM Committee wishes to add.

By assuming four extra hours of "partial ASP", the SEM Committee increases forecasts of IMR and lowers the Net CONE.[38] However, this assumption implies a lower security standard than at present, which would require a lower capacity requirement, and higher revenue per unit of capacity, which is only sustainable if the cost of new capacity is also higher than previously believed. Reconciling all these assumptions would require a detailed review. The SEM Committee cannot assume additional hours of LOLP on the supply side without making an equivalent adjustment on the demand side, which requires proper analysis. There are therefore no grounds for arbitrarily adding hours of "partial ASP" into the calculation of IMR and Net CONE.

The assumed IMR must be plausible in practice, not only in ideal conditions

The IMR in any one year depends on the actual conditions that generators will face in practice, not on ideal conditions of equilibrium, when the system is achieving the long run target for LoLH. The SEM Committee has acknowledged that available capacity will be above the target level, in the first auction at least. In conditions of excess supply, market participants will earn lower Inframarginal Rents than the SEM Committee proposes to assume when calculating the Net CONE. As a result, the SEM Committee's estimate of Net CONE will be biased downward.

It is inconsistent to set a demand curve for actual conditions, but to use equilibrium conditions to assess IMR element of Net CONE (and to prevent generators from offering above a limit set with reference to the resulting figure). If the SEM Committee uses the Net CONE of a new entrant generator in equilibrium conditions to set the upper limit on generators' offers, the

[38] Our calculations indicate that the inclusion of these four hours raises the IMR from €2.69/MWh to €4.03/MWh.

calculation will materially overstate generators' IMR, and artificially reduce Net CONE and offer limits (possibly by a large amount, maybe even as much as one third), which would discourage any new investment.

By adopting a method that is both inconsistent and subjective, the SEM Committee would be setting up the system to fail. The provision for exemptions would not operate properly as an appeals mechanism because exemptions would be based upon NGFC which excludes, amongst other things, sunk costs of recent investments.

The RAs themselves have indicated a desire to avoid an excessive reliance on unit specific bid offer limits as this would be an administrative burden on all concerned with little or no benefit to the consumer.[39] However, setting the Net CONE too low, by adopting inconsistent or implausible assumptions, is bound to provoke many requests for higher offer limits. The calculation of Net CONE must therefore be based upon a consistent set of parameters, including a deduction for IMR based on the conditions actually expected to pertain, not on an ideal or notional equilibrium.

There is no justification for changing the BNE forced outage rate

The move to I-SEM does not, in itself, justify any change in the FOR assumption for BNE plant. In principle, there is no need to use the same figure for: (1) marginal de-rating factors for the technology class of the BNE plant; and (2) the historical FOR for the BNE plant. The former measures estimated availability at times of system stress, whilst the latter applies over all periods. They are different concepts and we are concerned that the decision to change the FOR is not based upon sound reasoning, detailed analysis or coherent principles..

Inadequate consideration of other costs

The SEM Committee's approach lists specific cost items that may be included in offer prices. The list of cost items is inevitably incomplete, and will deny bidders the opportunity to recover all the incremental costs of making plant available, let alone any past costs of making plant available.

Even a cursory consideration of the new market arrangements suggests significant additional costs that generators will incur as a result of being awarded an RO – not just energy prices (difference payments), but also:

- the expected cost of termination payments (which may, admittedly, be small, once adjusted for the probability of incurring them); and

[39] The SEM Committee Locational Issues Decision Paper (SEM-16-081), published 8 December 2016, states in paragraph 5.4.14 that "…adopting an approach of scrutinising individual NGFCs could lead to a heavy administrative burden on both the RAs and the industry for little if any benefit to the consumer".

- the interest cost and fees of working capital needed to carry the risks of ROs (which the Northern Ireland regulator has recognised in the past as a basis for the margin in the regulated supply business.)

Some of these costs have yet to be determined, but they all represent incremental ("Net Going Forward") costs of accepting an RO. If RO prices do not cover all the incremental costs of making generation available, they will undermine the incentive to provide capacity (particularly because, in other workstreams, the SEM Committee is proposing tight restrictions either on pricing (DS3) or on offer submission – e.g. for non-energy actions which will be predominantly pay as bid).

The calculations will therefore have to take a wider range of incremental (net going forward) costs into account when calculating the cost of BNE generation and RO prices.

The need to update Net CONE annually

To preserve the transparency of regulation in the I-SEM, and to maintain incentives for efficient investment, the SEM Committee would need to commit to an annual process of re-estimating net CONE to reflect changing cost conditions, following extensive consultation with the industry, as is done for the BNE process at present. In the absence of an established, well defined, annual consultation process, market participants would be exposed to the risk that the SEM Committee will not revise net CONE estimates upwards when cost conditions increase. The multiple price caps referenced from net CONE would then not track market participants' underlying costs, undermining the principle of cost recovery.

The SEM Committee should therefore set out a well-defined, annual process for updating Net CONE to reduce the perception of regulatory risk.

Conclusions

The current proposals define a calculation of the Net CONE which makes arbitrary assumptions that are inconsistent with other assumptions and with the realities of the market. Such an inconsistent approach risks setting offer caps too low, unnecessarily adding to the administrative burden, and significantly increasing regulatory risk regarding cost recovery (for new and existing generators). To bid a price reflecting their actual costs, existing generators would have to apply for an exemption, but the chances of being awarded one are small, if the reason is disagreement over the rules. Granting an exemption would then require the SEM Committee to reject the previous basis of its own calculations, knowing that any adjustment made for an individual generator would invalidate the entire method. That is not a sound regulatory basis for long term investment incentives.

The only way to provide a stable and credible basis for calculating Net CONE is to adopt assumptions that are consistent with other CRM assumptions and with other parts of the I-SEM.

For the sake of transparency, the process for updating the calculation annually needs to be subject to clear rules of governance.

Auction Price Cap

6.6.2 Do you agree with the choice of multiple of 1.5 x Net CONE in setting the Auction Price Cap?

The proposed figure of 1.5 lies within international norms, but towards the lower end, especially since some regimes apply the multiple to the gross CONE (i.e. a higher figure, calculated before deducting IMR). Some well-established markets have adopted higher multiples. It the light of this experience, it would be prudent to take a multiple that was towards the top end of the international range for the I-SEM, because of its small market size, the lumpiness of demand and supply growth, and the lack of historic data regarding the new trading arrangements.

Justification provided for adopting a lower multiple is unsound

The SEM Committee justifies picking a lower multiple on the observation that the system currently has excess capacity of 3,730 MW. The SEM Committee concludes from this observation that market participants "found a capacity payment of less than 1x Net CONE adequate to cover their 'missing money'" in the SEM.[40] The SEM Committee is wrong to place its faith in the existing reserve margin as evidence that capacity providers require less than 1 x Net CONE, for at least three reasons:

1. The excess capacity in the SEM is due to the unforeseen reduction in electricity demand that followed the financial crisis in 2008, and to the continuing investment in renewables. Thermal investment was planned upon forecasts of demand that proved to be inaccurate, but was efficient and intended to capture high capacity prices during the forecast periods of shortage. Renewable investment was driven by non-market incentives. Therefore neither case support the view that investment is driven by prices set equal to 1 x Net CONE.
2. The SEM Committee's comments imply that the I-SEM would still attract investment if capacity prices were *capped* at 1 x Net CONE. However, given the variation in market conditions, that would mean capacity prices were only ever equal to Net CONE or less, which would not encourage investment. (Any obligation on generators to participate in the T-4 auction

[40] CRM Parameters Consultation Paper, para 6.2.19.

exacerbates this problem.[41]) In contrast, the current CRM offers a capacity payment that averages out at 1 x Net CONE, so investors expect the capacity payment to lie below that level at some times and above that level at other times. The potential for capacity prices to rise above Net CONE is required to offset periods when capacity prices fall below Net CONE, and any price caps must accommodate that variation.

3. The historical performance of the SEM is a poor indicator of the future performance of I-SEM. Market participants, entering with new plant designs, will face new and untested market arrangements, which deliberately limit cost recovery. (Some of the restrictions apply "only" to existing plant, but every new entrant will become an existing plant in the future.) Potential entrants will need to take into account both the increasing risks and costs of the new market arrangements and the increased regulatory risk under the I-SEM design. Few inferences can be drawn from investor behaviour under the current regime.

Evidence of regulatory risk will increase investment costs relative to other markets

The regulatory risk evident from SEM Committee decision-making so far in relation to I-SEM is also likely to make the market less attractive to new investors, compared with other more stable investment environments. Our answer to Question 6.6.1 highlights the arbitrary approach to decision-making being adopted in the calculation of Net CONE which contributes to this perception. There is also clear and abundant evidence of the SEM Committee's desire to curtail the ability of generators to recover legitimately incurred costs under the I-SEM market arrangements – e.g. the preference for overly prescriptive but necessarily incomplete, intrusive (and ultimately flawed) approaches to micro-managing generator revenues.

In the discussion of offer price caps within this Consultation Paper we see (1) the arbitrary exclusion of legitimately incurred costs (both sunk and incremental); (2) reliance on subjective judgement rather than objective principles; (3) a wide scope for errors in the SEM Committee's forecasts of future costs and revenues; and (4) proposed arbitrary approaches . Similar trends can be observed in the presentation of arguments supporting the BMOP.[42] On the other hand, we see absolutely no acknowledgment of the difficulties of determining accurate assumptions or carrying out accurate

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[41] If generators were free to allocate their capacity between the T-4 and T-1 auctions, they could decide to sell it all in the T-1 auction when capacity is tight and prices are high. However, the proposed rules will oblige generators to allocate most of their capacity to the T-4 auction, where the potential for new entry will cap prices at the actual Net CONE (which may be higher or lower than the SEM Committee's estimate). Existing generators will therefore be denied any major opportunity to capture high capacity prices sufficient to offset periods of surplus capacity when capacity prices are low.

[42] SEM Committee (2016), *Offers in the I-SEM Balancing Market: Consultation Paper*, SEM-16-059, 7 October 2016.

modelling, or recognition of the limited information that will be available to regulatory staff when carrying out these tasks.

The regulatory risk this creates, which permeates throughout the wider market design, make I-SEM a less attractive investment proposition than other electricity markets, and will result in consumers having to pay a premium relative to other markets to attract capacity. The Auction Price Cap therefore needs to be set at an appropriate level to reflect this reality.

Failure to address structural market power will increase investment costs

The failure of the SEM Committee to adequately address the structural market power of ESB, which has been clearly acknowledged in consultation papers and decisions published by the SEM Committee, further increases the risk of investing in the I-SEM.

The design of the I-SEM confers significant portfolio benefits on ESB, while also increasing their opportunities to exert market power to the detriment of their competitors in important markets, such as the intra-day energy market , and both the primary and secondary capacity market. The failure of the SEM Committee to properly address these issues will make I-SEM a less attractive investment proposition compared to other electricity markets, and will result in consumers having to pay a premium relative to other markets to attract investment. The Auction Price Cap therefore needs to be set at an appropriate level to reflect this reality.

The need for stability in the regulatory framework

The current surplus of generation capacity will not last for ever – indeed, it will be short-lived if prices are capped below actual avoidable costs. The market arrangements must include stable and credible provisions that encourage timely investment from the start – not a “bolt-on”, as and when a need suddenly arises.

Price caps will only bind when the market is short, at which point their dysfunctional nature will have the most serious effect, as the I-SEM struggles to attract new investment. Reacting to such negative effects by raising prices arbitrarily will not give investors the necessary confidence in long term returns. However, if the CRM sends stable and sustainable investment signals from the start (e.g. by setting the Auction Price Cap at 2 x Net CONE), the market will attract appropriate levels of investment when it is needed, while the increase in competition from new entrants that will result will increasingly lessen the reliance on the Auction Price Cap.

Definition and Calculation of Net Going Forward Costs

6.6.3 Do you agree with the proposed methodology of estimating a generator’s Net Going Forward Costs (NGFC) at:

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

The SEM Committee confuses "Missing Money" and NGFC

Throughout the discussion of Net Going Forward Costs in section 6.3 of the Consultation Paper, the SEM Committee confuses "missing money" with "Net Going Forward Costs".[43] In paragraph 6.3.13 in particular the statement that "[i]f this element of the formula [FOM – IMR] is zero or negative, then the generator has no missing money") is incorrect as explained below. As explained below, the concepts of missing money and NGFC are quite distinct:

Missing money is the *revenue* that the energy market fails to offer to *all generators* because its prices for energy and capacity (and potentially ancillary services) fail to reflect the economic value of electricity. That "missing money" occurs either because the regulators set explicit price caps below the level of VOLL, such as the €3,000/MWh price cap on the energy market in I-SEM, or because the threat of government intervention creates an implicit price cap.

Net Going Forward Costs are the *costs* that each generator would need to incur, on a forward-looking basis, to keep plant open and operational.

The SEM Committee's confusion over this distinction is instructive. In the context of competitive electricity markets (indeed, any competitive markets), market power mitigation would ideally mean preventing abuses *without hindering the competitive process*. However, the SEM Committee gives every impression of wanting to restrict prices to the level of generators' costs – as defined by the SEM Committee. The SEM Committee's view seems to be based on the notion that market power requires electricity markets to be regulated on the basis of the cost-of-service, where the cost-of-service is limited to avoidable (future) costs. The SEM Committee then discusses "missing money" only in terms of a failure to recover generators' Net Going Forward Costs in capacity markets (and/or their Short Run Marginal Costs in constrained energy markets). This approach is not consistent with allowing – let alone promoting – competition. It would also fail by the standards of monopoly regulation, since the SEM Committee argues it need pay no heed to sunk costs. It truly offers the worst of both worlds.

In a competitive market, it would be wrong to assume prices equal NGFC or SRMC at all times (even allowing for the loss of load hours when the Administered Scarcity Price applies), as the NERA Report confirms. In conditions of relative scarcity, or when sudden demands take the market by surprise, generators in competitive markets may earn high prices from being available and flexible enough to meet demand at the key moment. (There is nothing unusual in this observation. The same phenomenon is found in the

[43] See for instance paras 6.3.11-13 of consultation paper.

market for any commodity whose production and delivery to the market requires advance notice.) In these conditions, prices may be temporarily detached from the cost of production but, in a competitive market, anyone can earn these prices by investing to make plant available and flexible. Indeed, the prospect of earning such high prices is needed to attract investment in capacity and flexibility; the problem of "missing money" arises when this prospect is denied.

For the success of the I-SEM, it is vitally important that the SEM Committee focus on allowing competitive market prices and does not expect capacity market prices to be tied to a restrictive definition of "net going forward costs" or to the long term average costs of new entry (i.e. net CONE). In Consultation Papers produced in other workstreams,[44] the SEM Committee is proposing to tie market prices to a restrictive definition of short term marginal costs (currently for constrained "non-energy" actions, but potentially also for the unconstrained energy market if observed behaviour "is deemed to warrant" an extension of controls). Together, these policies would produce a potentially disastrous combination, in which restrictive regulation gave the generators required for system security no prospect of recovering their total costs, and any other generator might quickly find itself in the same position. A totally different approach – and closer coordination between workstreams – is required to avoid such outcomes.

We – and, we hope, the SEM Committee – take it for granted that a competitive market must offer generators the prospect of recovering their total costs plus a reasonable rate of return over the long run. In this respect, one cannot distinguish between new and existing generators since, over the long run, today's new generators are tomorrow's existing generators. (Such distinctions may be discriminatory. They might also cause the inefficient closure of generating assets required for system security.)

Regulating competitive markets by reference to costs is not efficient, practical or in consumers' interests, as it would eliminate the benefits of competition whilst offering none of the benefits of monopoly regulation. Instead, the SEM Committee should ensure that any attempt to prevent abuses still gives the competitive process room to flourish, so that generators have the flexibility to recover their costs plus a reasonable rate of return where and when the market allows.

Capping bids at NGFC can prevent cost recovery and damage incentives

In a clearing price auction for capacity, successful bidders receive a capacity revenue set by the bid of the marginal plant, which in general lies above their own Net Going Forward Costs. The extra revenue offers some prospect of

[44] E. g. SEM Committee (2016), *Offers in the I-SEM Balancing Market: Consultation Paper*, SEM-16-059, 7 October 2016.

recovering other costs (although restrictive price caps can disrupt the chances of total cost recovery). However, in some conditions, requiring market participants to set their bids no higher than their NGFC may systematically deny cost recovery and therefore threaten security of supply for the reasons explained below.

Some plants will earn a price that equals the SEM Committee's estimate of their NGFC and offers no prospect of recovering sunk or other costs. This plant might even fail to recover its true NGFC, if the SEM Committee underestimates it.

The marginal plant in any capacity auction falls into this category, but so too do generators that are out of merit but required for system security; they will be "constrained-on" in the capacity market, required to bid a price equal to their NGFC (assuming it lies above the ECPC), and paid their bid price. This combination of rules would have adverse consequences for system security.

So-called "existing" generators cannot remain available indefinitely without occasional expenditure on refurbishment and repairs. This expenditure is normally incurred in one year and amortised over the following 5-10 years or longer. Under the proposal to limit bids to NGFC, existing generators will not be allowed to include these costs in capacity market bids for any year: before they are incurred, they are out-of-period; after they are incurred, they will be "sunk costs".[45] The inability to recover such costs would encourage existing plants to close, requiring new plants to enter the market (on the promise of a long term contract), even thought that is unlikely to achieve the least-cost or most efficient outcome.

This problem will be particularly serious for Reliability Must Run plants, i.e. plants needed for reasons of system security. Rules that prevent long term cost recovery will lead to the closure of plants whose capacity has a particularly high value to consumers.

The value of such plants is defined only in part by allowing capacity bids that cover all the costs of keeping the plant available; the competitive market price of such plant is often defined by the cost of alternative measures to achieve the same level of security. (This policy has been applied with some success in the British electricity market, whenever the system operator negotiated a contract to keep a generator available for system support.) Such generators cannot demand a price higher than the cost of alternatives, such as investment in the transmission network, or they will price themselves out of the market.

[45] Bidding in T-4 auctions might conceivably offer a short window, during which the expenditure due in the year T-1 is anticipated in years T-4 to T-2, and not yet sunk. However, forcing generators to recover long term investments within this arbitrary period will produce high bid prices and inefficient auction results.

Thus, it will be essential to allow some flexibility for generators to bid more than NGFC, because of the necessity of recovering sunk costs.

The Consultation Paper is not clear how the mechanism will set shortage prices in T-1 capacity auctions, when new entry does not act as a *de facto* cap on prices, but capping T-1 auction prices at NGFC will destroy incentives to keep capacity available.

If insufficient capacity is available to meet demand in any auction, prices should be defined by the demand curve, i.e. rise to the auction price cap, to provide a signal of the need to make more capacity available. If the cap on T-1 prices is too low (e.g. by reference to NGFC or to prices in the T-4 auction), generators who fail to win an RO in the T-4 auction will have no further incentive to maintain their plant's availability. That might result in a shortage by the time of the T-1 auction. In such conditions, tying offer prices and auction prices to costs would not be efficient and would not support security of supply. Some generators would end up earning less than their costs in surplus years (because they receive no RO), but would then be prevented from earning more than their costs in deficit years (by the various caps). Over the long run in an uncertain world, such a regime guarantees under-recovery of costs and provides no incentive for any existing generators to remain available.

New entrants will be able to access long term contracts under the SEM Committee's current proposals. In the year following the award of an RO, a new entrant will no longer participate in the capacity market, and the remainder of the market is likely to be in surplus. In the year in which entry occurs, prices will only rise to net CONE (spread over a 10-year contract) but they will remain below that level during times of surplus, until new entry is required again. Over the long run, the incentive to maintain and operate existing capacity will remain systematically below the incentive for new plant and would deny recovery of sunk costs at least for some plant.

The SEM Committee's definition of NGFC is incomplete

The SEM Committee has tried to define NGFC from the bottom up, by identifying and allowing individual costs items. This approach is prone to catastrophic error, since any omission would result in offer prices – and hence some auction prices – lying below the marginal costs to making plant available. Equivalent problems with the proposed controls on offer prices in the energy market will compound the difficulties that generators face with recovering their marginal costs, let alone their total costs. The SEM Committee's proposed approach will result in inefficient closures, discourage efficient investment and threaten security of supply.

Given the difficulty of specifying generator costs with any precision in simple rules, the only feasible approach is to adopt a general description of the associated costs, subject to a set of guiding principles on the interpretation of this description. To follow the example of SRMC, the full calculation of Net Going Forward Costs ("NGFC*") should rely on identifying the difference between total future costs (less revenues) when the plant is available and holding an RO, and total future costs (less revenues) when the plant is closed. Here, "costs" include all costs arising from the RO (i.e. difference payments or other penalties), and "revenue" refers only to revenue from energy and ancillary services ("E&AS") and excludes RO payments for capacity:

NGFC* = [Total Costs (if available and holding an RO) – Total Revenues (E&AS only)]

- [Total Costs (if closed) – Total Revenues (if closed)]

The SEM Committee's definition of NGFC effectively replaces "Total Costs" with "fixed operating costs (FOM) plus variable costs (VOM) plus difference payments" and also replaces "Total Revenues" with "inframarginal rent (IMR) plus variable costs (VOM)". The SEM Committee then assumes that, if the plant is closed, these items of cost and revenue all equal zero, thereby eliminating the second row of the formula above. These assumptions simplify the formula to the following:

NGFC = (FOM + VOM + Difference Payments) – (IMR + VOM)

NGFC = FOM + Difference Payments - IMR

The SEM Committee's definition of NGFC will be incorrect if any part of its shorthand definition of either costs or revenues is incomplete. For example, the SEM Committee's proposal omits the following categories of costs:

- Costs of any prospective investment (which may or may not allow admission as a new build generator under the capacity market rules);
- Costs of past investment, including recent investment required to keep plant available;
- Expected costs of holding an RO other than difference payments, such as termination fees or any other penalties that may be imposed under the RO (with a probability greater than zero); and
- Costs of risk or working capital to deal with variations in earnings.

In defining NGFC, the SEM Committee observes that "the NFOC contains a proportion of Variable Operating & Maintenance (VOM) costs which can be recovered via the energy or ancillary service markets". However, the SEM Committee has also issued a Consultation Paper on offer price controls in the Balancing Market which explicitly states that *"maintenance costs are not considered variable in nature and are therefore not considered by SEM*

Committee as eligible cost items for inclusion in offers".[46] These two statements are inconsistent.

The SEM Committee is simultaneously (1) arguing that variable maintenance costs exist but should be recovered through energy markets (rather than capacity markets), and (2) denying the existence of variable maintenance costs and preventing their inclusion in energy market offer prices. This blatant inconsistency between two Consultation Papers is just one example of the type of error that will hamper any attempt to define a restrictive list of allowed costs. (For the record, variable maintenance costs do exist, and the restriction on energy market offer prices is based on an error of fact.) The proposed approach is therefore bound to fail, because any omission will cause prices to fall below marginal costs and thus set up an incentive to minimise output.

Even for those cost and revenue items which are explicitly included within the SEM Committee's proposed definition, the SEM Committee may underestimate the costs incurred or revenues earned by plant on the system. We discuss this possibility further in response to 6.6.4 below.

6.6.4 Do you agree with the proposed process and data inputs to calculate NGFCs as set out in 6.3?

The SEM Committee has two stated purposes for its calculation of NGFCs.

First, the SEM Committee will calculate NGFC for the plant on the system as a cross-check on the level of the Existing Capacity Price Cap for the market as a whole. (We note that the SEM Committee intends to set the offer cap for existing capacity above the NGFCs of "the majority of existing plant". However, the SEM Committee is also proposing an additional cap for the first transitional auction that would stop this rule from setting a price cap above Net CONE.[47])

Second, the SEM Committee states that it will "take into account" the NGFC it calculates for each plant when assessing any applications to bid above the Existing Capacity Price Cap.[48] The SEM Committee is not specific about how much weight it will accord to its estimates of NGFC in this evaluation. However, the SEM Committee appears to regard its *own estimate* of an applicant's NGFC as the effective cap on that applicant's bid.

The SEM Committee proposes to calculate NGFC as follows:[49]

- Identify the FOM costs of the unit in question from the generator's financial reports;

[46] SEM (2016), *Offers in the I-SEM Balancing Market: Consultation Paper*, SEM-16-059, 7th October 2016, page 16.
[47] Consultation Paper, para 6.3.4.
[48] Consultation Paper, para 6.3.6.
[49] Consultation Paper, Figure 8.

- Calculate IMR based on a PLEXOS run for the entire market (which the SEM committee will also presumably use, although it does not say so, to estimate difference payments under the RO); and
- Calculate unit specific ancillary service income by scaling historical ancillary service income by the rate of increase in the ancillary service budget.

This proposal, to identify FOM costs from generators' financial reports, would require the SEM Committee to make subjective assumptions. It does not provide a robust, objective basis for the calculation of NGFC, since accounts do not show economic (opportunity) costs, or the split between fixed and variable costs, that the SEM Committee would wish to use. The SEM Committee proposes to eliminate both variable costs and future (or perhaps mandated) "efficiency gains" from the unit's total FOM costs but again will not be able to identify these components of total FOM costs without relying on subjective estimates.

(In any case, as discussed in Question 6.6.7 below, the SEM Committee have no grounds for disallowing higher FOM costs on the mere presumption that they are *inefficient*. Commercially motivated participants already have an incentive to maximise profits and hence to minimise costs. The SEM Committee should therefore proceed from the assumption that their costs are as low as efficient operations dictate. The observation that FOM costs within the SEM *differ from* international benchmarks provides no evidence on relative efficiency.)

The SEM Committee's proposal to use a PLEXOS run to identify energy market revenues would create another complex and highly subjective exercise. In order to forecast generator revenues, the SEM Committee would have to form a view on the following parameters, at least:

- Fuel prices for the duration of the modelling period;
- The precise capacity and mix of plant on the system, including any new entry;
- Levels of outturn wind;
- Fuel efficiency rates and variable O&M costs for each plant on the system;
- The level of demand and changes to the demand profile over time; and
- Electricity prices in Great Britain and the future use of the interconnectors between the I-SEM and Great Britain.

Whilst the SEM Committee's proposals to identify energy market revenues are complex and subject to very significant forecast error, its proposals for identifying ancillary service revenues are merely arbitrary and inevitably inaccurate. The SEM Committee implicitly assumes that each unit will capture the same proportion of the ancillary services budget in the future as it has in the past. In practice, the need for ancillary services shifts over time as the pattern of generation and demand changes. The SEM Committee's estimates of NGFC may therefore materially overstate ancillary service revenues for plants that have played a major role in the past, but which should expect a declining share of ancillary service revenues in the future.

Leaving aside the subjectivity of the assumptions used in its analysis and the remarkable scope for forecast error, the measure of NGFC proposed by the SEM Committee does not even in principle provide an accurate measure of the underlying NGFC incurred by generators. The SEM Committee's proposed process calculates the costs and revenues in any given year. By assuming that units need to recover the NGFC of each year in that year's capacity market, the SEMC Committee is assuming that decisions to keep plant available or to close it are independent between years. In practice, this assumption does not hold, because closure decisions tend to be irreversible: when considering whether to close plant in the current year, generators must take into account the potential loss of revenues (and costs) from operating in future years.

For instance, if a generator expects electricity prices to rise, it might continue to operate plant even if it made losses in the short run, because closing it now would remove any chance of earning profits later. In effect, the generator would (expect to) recover some of this year's costs from future years' revenues. The correct economic basis for estimating NGFC would take into account revenues and costs over the whole remaining economic life of the units concerned, including any future capacity payments. If instead the SEM Committee insists that a generating unit may not include previous years' costs within this year's NGFC, its calculations must allow the plant required for system needs to recover its annual costs within every year, regardless of current market conditions.

Thus, the proposed method of calculating any generating unit's NGFC is inevitably a subjective exercise, reliant on estimates of the fixed share of O&M costs and their value at Opportunity Cost, of future fuel prices, of ancillary services revenues (merely by scaling historical revenues), and on modelling of electricity markets. The SEM Committee cannot possibly know the future cost structure of the generators, or generators' business plans, as well as the generators do. Its estimates may therefore be wildly inaccurate.

Accordingly, when setting the Existing Capacity Price Cap on the basis of NGFC, the SEM Committee will need to build in a very significant margin for error above its own estimates and forecasts, just to be sure that market participants have room to bid their actual NGFC.

Instead of relying on its own subjective calculations when evaluating applications to bid above the Existing Capacity Price Cap, the SEM Committee should specify the overall economic framework for estimating NGFC, which should include provision for recovery of total costs (including sunk costs and a return on capital) and ask the generators to quantify their costs and to justify their figures. The SEM Committee would then only need to scrutinise informed estimates and the supporting information, rather than acting upon ill-informed guesswork.

Existing Capacity Price Cap 6.6.5. Do you agree with the proposed approach of setting the Existing Capacity Price Cap at 0.5 x Net CONE? If not explain why, your preferred alternative approach and your rationale for the alternative.

Energia does not support the imposition of an Existing Capacity Price Cap as we believe it may be discriminatory. If the SEM Committee proceeds with an Existing Capacity Price Cap then we recommend it is set at a much higher level than 0.5 x Net CONE to avoid the under recovery of costs, recognising the risks when setting the cap are asymmetrical, with significant more downside resulting from underestimating it than over-estimating it.

The proposed level of the Existing Capacity Price Cap is too low

It is essential for efficient market outcomes, and to promote security of supply, that offer caps are set at a level that is sufficient to facilitate recovery of costs with minimal regulatory risk. The risks associated with the setting of the Existing Capacity Price Cap are asymmetrical, with significant more downside from underestimating the offer cap (increasing the risk of under recovery of costs) than over-estimating it.

The SEM Committee argues that the Existing Capacity Price Cap should be set at 0.5 x Net CONE because:[50]

"If set at this level, we estimate that the almost all of plant required to meet the Capacity Requirement could bid at its NGFC without needing to apply for a unit specific bid limit"; and

"It is consistent with relevant international benchmarks".

The SEM Committee does not provide its workings so it is not possible to verify the statement about generator costs in the first bullet. Based on the incentive to withdraw plant if they are not recovering costs, however, we can see no reason why a price cap should be set any lower than the costs of the most expensive generator and indeed should be set above these if based on historical analysis to account for variations year on year. For example, under the proposed capacity market rules long term maintenance costs cannot be amortised without significant cost recovery risk due to the exclusion of sunk costs from the definition of NGFCs and therefore these costs will need to be fully recovered in the year they are incurred. Leaving to one side the clearly significant problems these rules create (discussed in sections 3 to 5 of this response); they will result in substantial annual variations in generator costs.

[50] Consultation Paper, para and 6.3.33.

As for the second bullet, the SEM Committee does not cite the specific international benchmarks it is relying upon, nor ensures comparisons are on a like-for-like basis with regards to participant outcomes when the wider market arrangements are taken into account. Regardless, our review of international regimes has presented no grounds for the level, or indeed the existence of Existing Capacity Price Caps proposed by the SEM Committee. In particular:

Any apparent similarity between the scheme in GB and the proposal for the I-SEM is only superficial, because of crucial differences between the wider energy and capacity trading arrangements in each market.[51] In the British capacity market, existing units do not have to demonstrate to National Grid or Ofgem that they need a price in excess of the price-taker threshold – i.e. there is no ex-ante regulation of offer submissions. Instead, operators must only submit a memorandum stating that they need to recover costs in excess of the price-taker threshold, along with the supporting evidence for their case *contained in a sealed envelope*. Ofgem never scrutinises this evidence until after the auction has taken place, and then *only if Ofgem has grounds to suspect wrongdoing*. In other words, the price-taker threshold does not prevent bidders from bidding their own estimate of Net Going Forward Costs, except after full and proper consideration of an alleged market abuse. Furthermore, in Great Britain cost recovery for system actions (non-energy actions in I-SEM terminology) is not capped ex-ante at a restrictive, and demonstrably flawed, calculation of SRMC. Therefore, a unit offering at its NGFCs into the capacity market in GB can recover rent from the energy market even when constrained on to offset its sunk costs. These are crucial differences between the regulatory regimes in Great Britain and I-SEM that ought to be properly taken into account.

International precedents therefore do not provide the SEM Committee with any justification for imposing a price cap of 0.5 x Net CONE on existing capacity or capping cost recovery of constrained on generators, or in merit generators that require a unit specific bid limit above the Existing Capacity Price Cap, at NGFCs, which systemically denies the recovery of legitimate costs (see NERA Report for details).

Implications of setting the Existing Capacity Price Cap too low

Within the context of the wider market rules setting the Existing Capacity Price Cap too low impose unnecessary administrative burdens on participants and the regulatory authorities, and significantly increase regulatory risk, because of an increased reliance on Unit Specific Bid Limits. In combination with the restriction that such bid limits are capped at the SEM Committee's narrow definition of NGFCs (which as our answer to the question above demonstrates is incomplete) means that the regulatory regime will deny legitimate cost

[51] See NERA (2016b), Competition and Cost Recovery under the I-SEM Bidding Rules: A Report for Viridian, 19 December 2016.

recovery via the capacity market for units that are not, or are barely, infra-marginal. In the case of such generators that are also constrained on for system security reasons in the balancing market, the regulatory regime will also restrict their cost recovery to the SEM Committee's definition of SRMC (which has also been demonstrated to be flawed).[52] As ancillary services revenues are based on tariffs, this culminates in a regulatory regime across energy, capacity and ancillary service market that systemically denies recovery of legitimate costs, particularly for constrained on generators. We cannot see how such arrangements are in anyone's interest, least of all the consumers.

Implications of applying an Existing Capacity Price Cap to T-1 auctions

The competitive market prices in short term auctions differ in nature from those in auctions where new entry is possible. Application of an Existing Capacity Price Cap in the T-1 auction will distort market price signals and incentivise potentially inappropriate closure of generation assets.

In most years, the T-1 auctions will produce prices below Net CONE, because of surplus capacity. However, in some years, capacity will be short of the target, e.g. because new plant construction is unexpectedly delayed, or because demand is higher than expected. In these conditions, the competitive market price in a T-1 auction would lie above Net CONE.

The implications of suppressing prices at times of actual shortage would be severely detrimental to security of supply. Setting T-1 auction prices at net CONE *or less* would prevent capacity that did not clear in T-4 auctions from remaining available until the T-1 auction to cover any potential future shortfall in capacity. [53]

Imposition of an Existing Capacity Price Cap may be discriminatory

Imposing a blanket offer cap on existing capacity may be discriminatory. In principle, capacity provided by entrants and incumbents is of equal value to consumers. The rules applied to incumbent and entrant bidders ought therefore to be the same (as argued in Energia's response to the third capacity market consultation, page 5), unless the SEM Committee can offer an objective justification for discriminating. This has not been provided and Energia would observe that maintaining existing generators have lower costs

[52] See NERA (2016), Consultation Paper SEM-16-059: Offers in the I-SEM Balancing Market, A Report for Viridian, 17 November 2016.

[53] We note the current grid code requirements prevent a generator from waiting until the results of the T-1 auction prior to taking a decision to close. This is due to the requirement to give three years notice of closure and the inability to rescind such a notification. We are of the firm view that such restrictions are entirely unjustified and unreasonable in the context of I-SEM. These grid code restrictions should be reviewed in light of the trading arrangements that are being put in place for the I-SEM capacity market as currently the two set of arrangements are not fully compatible and will result in inefficient outcomes for consumers. 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 Code) must allow exit in the same timeframe as signals given by the market.

than new entrants and “do not need the money” is merely to argue that discrimination is justified because it is *possible*. A condition that would be met in almost every market where costs of supply differ between different producers.

6.6.6 Do you think that the NOFC costs reported by generators to the RAs as part of the SEM Generator Financial Reporting are a good proxy for the Fixed Operating and Maintenance costs that a capacity provider may need to recover via the I-SEM CRM, or do you think that the NFOC contain material variable cost which can be recovered via the energy / ancillary services market? If the latter, how big an adjustment should the SEM committee make to exclude any variable elements of the NFOC from NGFCs included in the Existing Capacity Price Cap?

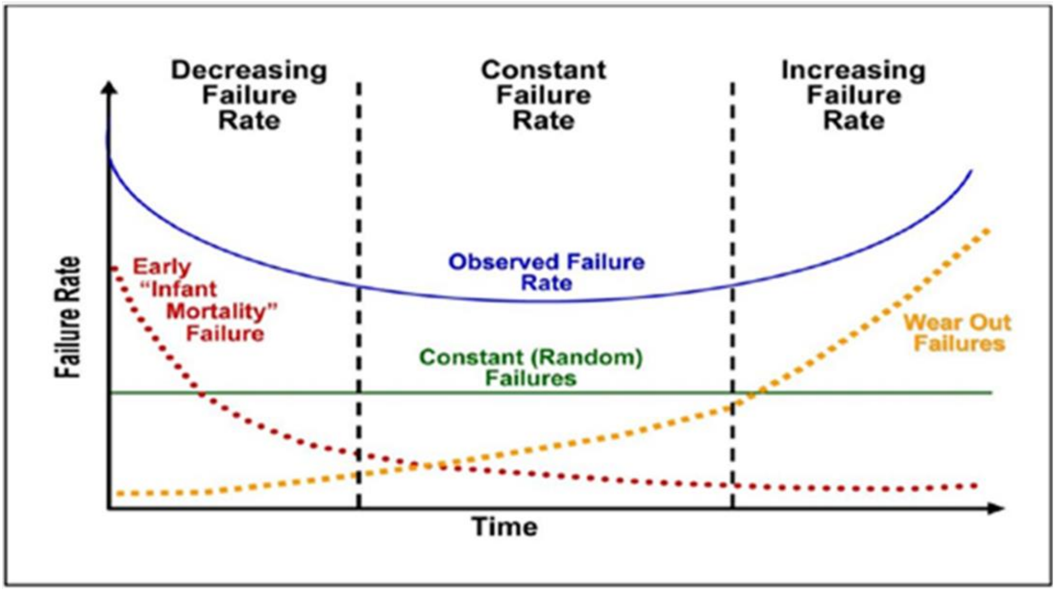
The costs reported in the SEM Generator Financial Reporting represent a true and fair view of the business, as required by any accounts, but they do not provide any basis for regulatory interventions in competitive markets.

Accounts show *historic costs*, calculated in accordance with *accounting conventions* of the day. They do not present costs according to economic definitions such as marginal costs or opportunity costs. Furthermore, accounts rarely distinguish clearly between fixed and variable costs. Therefore, the NFOC reported in accounts may include material variable components, or costs that do not reflect economic definitions. Attempts to define price caps in the capacity market will therefore require extensive manipulation of accounting data, including accounting adjustments made from time to time which can be highly material. It would also require adjustments to accounting data to provide a *forward looking view* of *economic costs* taking into account the aging of plant fleet (see Box 1 below), potential changes to its running regime including the costs of cycling, changing RoCoF standards and so on, and (more onerous and costly) environmental protection commitments going forward.

In conclusion, therefore, the SEM Committee cannot reasonably expect to acquire from generator financial reports the detailed knowledge necessary to replicate competitive market bids for every source of capacity. Attempting to hold down bid prices for all existing capacity on this basis is therefore fraught with the risk of under-pricing, and an unduly restrictive intervention in competitive market pricing.

Box 1: Aging of plant fleet

Historical data in accounts does not reflect additional maintenance and fleet issues going forward. An overall technical assessment should be considered to account for this. The 'bathtub curve' is widely used in reliability engineering. It describes a particular form of the hazard function which is the sum of three parts: The first part is a decreasing failure rate, known as early failures. The second part is a constant failure rate, known as random failures. The third part is an increasing failure rate, known as wear-out failures.



6.6.7 Why are reported SEM generator NFOC/FOM costs substantially higher than international benchmarks? Do you think that existing SEM generators have material scope to cut fixed operating and maintenance costs, and if yes, do you think that this should be reflected in the Existing Capacity Price Cap? Explain why.

FOM costs may vary between generators internationally for any of a wide range of reasons. Observing a difference in costs does not imply that the higher cost generator has material scope to cut costs. In fact, no conclusions can be drawn from merely observing a difference in cost, without investigating in detail the source of each cost individually. The information quoted by the SEM Committee provides no basis for setting or adjusting the cost data used to decide auction price caps.

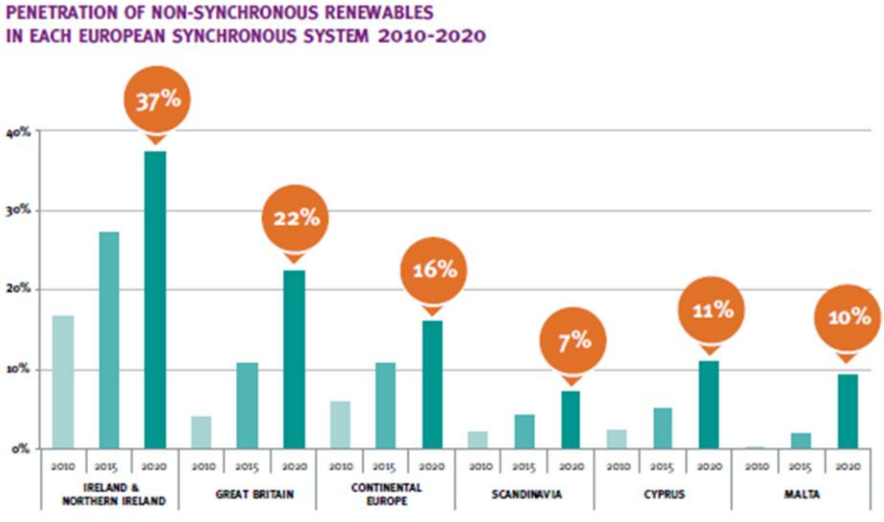
Costs may differ for a number of historical, geographical, environmental, policy-related, legislative, or security of supply reasons (and these differences may even affect plant differently *within* jurisdictions), including the following (a non-exhaustive list):

- Cost conditions may vary between international markets due to differences in regulatory conditions, wage rates, taxes and transport costs;

- Exchange rate fluctuations may cause costs incurred at similar levels in one year to appear different in later years;
- Accounting standards vary by jurisdiction, and not all accounts may be prepared according to the same standards (or IFRS);

Box 2: High penetration of wind in the SEM and its impact on thermal generation costs

High Penetration of Renewables: The Governments in Ireland and Northern Ireland have a target of generating 40% of electricity consumed from renewable sources by 2020 and a large proportion of this will come from wind. It was 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.



Source: The National Renewable Energy Action Plans (NREAP)

Plant cycling costs: The high penetration of wind directly impacts the amount of cycling experienced by thermal plant in SEM and this has cost implications. Factors which contribute to the total cost of cycling are: (i) increased fuel consumption due to increased plant start-ups and operation at part-load levels (and therefore reduced efficiency), (ii) increased fuel consumption due to loss of plant efficiency arising from increased wear to components, (iii) increased operations and maintenance (O&M) costs due to increased wear-and-tear to plant components, (iv) increased capital costs resulting from component failures, (v) increased environmental costs resulting from increased emissions, and (vi) loss of income due to longer and more frequent forced outages.

Other costs:

- Reducing minimum generation: this will lead to increased maintenance costs due to additional corrosion and parts consumption.
- RoCoF – additional frequency fluctuations meaning additional wear and tear on the machines.

- The timing of intermittent costs may differ between comparators (e.g. operating and maintenance costs in Ireland may have been higher in particular benchmark years due to significant maintenance outages that occurred in other years elsewhere); and
- The age and type of plant varies between jurisdictions and may lead to substantial cost differences, e.g. because the small size of the Irish market and the history of its demand growth does not permit plants large enough to achieve the full economies of scale, or rapid replacement of old plant with lower cost new plant.
- Variations in security of supply commitments between jurisdictions, for example in Ireland regulatory rules dictates that CCGTs must hold between 3 and 5 days of secondary fuel based on their running profile, which is costly to both stock and maintain[54]. Such onerous requirements may not apply in other larger or less isolated markets.
- Different environmental protection commitments may apply across jurisdictions. In Ireland for example there are financial provision requirements relating to Closure, Restoration, Aftercare and Management Plan (CRAMP) which may differ from other jurisdictions.
- Grid-related costs (such as TUoS and Gas Capacity) will differ markedly across jurisdictions and will be comparatively high in smaller, less densely populated, islanded jurisdictions such as Ireland, as the CER themselves have acknowledged.[55]
- The evolution of energy policy may require different forms of adaptation by existing plant with differing costs (e.g. the recent and rapid growth in intermittent renewable technology has required existing generators to adapt their plant to make it more flexible, raising its cost relative to plant in markets where these effects are less prevalent. The cycling (and other) costs associated with facilitating a high penetration of renewables is an important consideration in the al-island context which is relatively small and highly constrained (as recognised by the MMU in the SEM[56]) when comparisons are made with other jurisdictions (see Box 2).

The SEM Committee has not provided detailed sources for its cost estimates. It is not possible therefore to identify exactly which of the factors listed above (or which other factors) explain the observed differences in measured FOM costs between Ireland and other jurisdictions. Whatever the reasons for the difference in costs, there is no reason to presume that the differences are due to inefficiency (or to any other reason, for that matter). The international cost

[54] Large levels of fuel need to be held on site that can increase the plants environmental protection commitment (ELRA and CRAMP) and there is a working capital impact. Fuel degrades over time so needs to be constantly tested and periodically replenished to allow safe use in the machine in the event of a secondary fuel requirement

[55] See for example 'CER Factsheet: Electricity Network and Charges', available online: http://www.cer.ie/docs/000910/cer10106.pdf

[56] SEM Market Monitoring Unit (2010), *Power Plant Cycling*, SEM-10-002, 18 January 2010.

data therefore provides no grounds whatsoever for the SEM Committee simply to assume that costs will, or should, be lower than they really are.

Commercially operating, profit-maximising firms always have an incentive to minimise their costs when confronted with prices that are determined by factors over which they have little or no influence, such as competitive market prices or (in the current instance) the formula for capacity payments in the SEM. There are no grounds for the SEM Committee to assume *either* that generators have not been minimising their costs so far *or* that arbitrarily cutting prices would encourage improvements in efficiency.

In practice, cutting prices arbitrarily, on the basis of specious arguments about the management of commercial firms, is more likely to harm efficiency that to promote it. If the SEM Committee allowed market participants only to bid its estimate of "efficient costs", based on *assumed* efficiency improvements, it would damage the economic incentives to make plant available. Market participants would be unable to earn sufficient revenue to cover their actual marginal costs.

The cost data from international sources is therefore useless for the purpose of setting price caps. It does not show what generators' costs *should* be in the I-SEM, as a basis for setting auction price caps. Nor does it show what generators' costs *will* be in the I-SEM, if the SEM Committee sets an auction price cap below generators' costs as currently observed. Attempting to use such data to set auction price caps would rely on arbitrary presumptions that undermine the transparency of decision-making in the I-SEM, destroy incentives to make plant available efficiently, and threaten security of supply.

Demand curve parameters

6.6.8 Which of options A, B or C with respect to the demand curve set out in Section 6.4 do you think is appropriate for the first transitional auction, and why?

Energia supports the demand curve maintaining the auction price cap up to the capacity requirement and favours Option A, which has the shallowest gradient from net CONE to zero price. Option A will increase the likelihood that additional capacity above the capacity requirement is procured lessening the impact of the 'lumpiness' issue and reducing locational concerns. A shallower demand curve will also help to smooth out volatility in the capacity price, which may otherwise prevent the capacity market from providing a stable, credible investment signal.

Option C is a compromise between simple linear interpolation and the TSOs' modelling of the value of Expected Unserved Energy. The TSOs' modelling however is not transparent and by the SEM Committee's own admission is "incomplete and subject to modelling uncertainty".[57] It would therefore not seem prudent to use the analysis to inform decisions about the appropriate shape of the demand curve.

Option B is the steepest demand curve overall and therefore will exasperate the issues alleviated by Option A. It should therefore be rejected on this basis.

International Precedents

Precedent from international jurisdictions also supports adopting Option A: The demand curve in New York City, which has a larger electricity demand than I-SEM, sets the capacity price equal to zero only when the volume of capacity winning in the auction is 18 per cent higher than capacity requirement.[58] The SEM Committee argued in the CRM 3 Decision Paper that shallower demand curves were the "direction of travel" in international capacity markets.[59]

6.6.9 Do you have any other comments on the shape and/or positioning of the demand curve for the first transitional auction?

The CRM aims to provide a predictable and efficient investment signal to market participants to invest (when needed) in new capacity and exit the market when it is efficient to do so. In order to achieve that objective, the CRM must be:

- **Transparent** - such that market participants can predict the evolution of the market over time and make informed entry and exit decisions;
- **Objective** – such that the parameters supporting the design of the market clearly reflect the SEM Committee's goals of efficiency and competition; and
- **Stable** – such that the SEM Committee allows the market design to function over time and refrains from adjusting the market design to achieve short term objectives (such as artificially lowering prices); any such behaviour would seriously undermine investor confidence in the stability of the market, put at risk security of supply and therefore be inconsistent with the long term interests of consumers.

These criteria must apply from the first transitional auction, to give market participants confidence that they can rely on the enduring regime, and to avoid regulatory risk becoming synonymous with I-SEM.

Locational parameters

6.6.10 If the SEM Committee proceeds to incorporate locational requirements within the I-SEM CRM, do you agree that the costs/risk of

[57] CRM Parameters Consultation, para 6.4.19.
[58] CRM Parameters Paper, para 6.4.24.
[59] CRM 3 Decision Paper, para 4.7.38.

implementing local demand curves (as opposed to a minimum requirement) outweighs the benefits?

Energia agrees that the costs/risks of implementing local demand curves as opposed to a minimum requirement outweigh the benefits. The SEM Committee has not provided any basis for defining local demand curves or evidence that the implementation of such curves will improve outcomes for consumers.

Section 7 – Load Following for Secondary Trading

7.2.1 Do you have any comments on the approach to setting the load following parameter set out in the section? Specifically do you agree with the granularity of the parameters, the proposed historically based methodology, and proposed governance approach? If not, why not and what other arrangements would you propose?

Energia provides its views on each requested area below:

Granularity

We support calculations on a monthly basis – i.e. so the load factor for a time of day period is set for each month. In relation to time of day periods, in principle it would be useful to align these with secondary products sold as much as possible for the sake of simplicity. An example might be winter peak (5pm to 9pm October to March), mid merit 2 (7am to 7pm), extended mid merit 2 (7am to 9pm) and baseload (all day). We appreciate other participants may have other views and it may therefore be sensible to determine final time of day periods when secondary products are consulted upon.

Historical Analysis

We would welcome some forward looking analysis to be taken into account when determining load following factor as well as any obvious outliers in the historic data to be taken into account. We believe this would help reduce the need for less of a safety margin as contextualised historical analysis, informed by forecast demand, should in theory result in more accurate factors. We would appreciate if the assumptions employed in the production of forecasts, and the methodology used to adjust historic data, could be published and the process made as transparent as possible.

Proposed Governance

While we see benefit in having a regularly updated process with a SEM Committee approved methodology, as it should allow for less of a safety margin, at least closer to the delivery period, we could see how this could become extremely complex. If complexity is an issue then the proposed approach of the SEM Committee approving factors year ahead seem reasonable – providing factors are not overly prudent (volumes are not unnecessarily restricted) and participants are able to trade in the secondary capacity market in line with primary capacity auction timelines. This latter point is discussed in our answer to the next question.

7.2.2 Do you think that capacity providers should be able to trade against load following margin in calendar year +2 and any subsequent years, and should the parameters for subsequent years be scaled to 75% of the calendar year Y+1 values or some other percentage?

Participants should be able to secondary trade their capacity positions more than one year in advance to allow them to manage exposures as flexibly as possible. In theory, participants should be able to trade as far out as there is awarded primary capacity but in practice a period of two to three years should suffice.

We appreciate the issues associated with forecasting load following factors several years in advance however, and therefore the stepped percentage approach outlined in paragraph 7.1.14 of the consultation paper may be a useful compromise. We would appreciate if the percentages could be as high as possible however to maximise potential secondary trade volumes.