Response by Energia to SEM Committee Consultation Paper SEM-18-028

Capacity Remuneration Mechanism (CRM) Parameters for T-4 2022/23 Capacity Auction

26 June 2018

Table of Contents

Executive Summary

In this response we explain, among other things, why (1) the caps on bid prices need to be amended to include a wider range of forward-looking costs than allowed in the T-1 auction, specifically the cost of financing, and (2) the rules for setting prices actually paid to constrained-on generation should permit prices closer to the competitive market outcome as described herein.

These and other fundamental issues identified and evidenced in this response require the urgent consideration of the SEM Committee before the T-4 parameters are finalised, having regard to their importance to security of supply, promoting competition, protecting the interest of consumers and ensuring that licensees can finance their activities.

The RAs cannot rely on the purported requirement under the Grid Code to give 3 years notice of closure to ensure security of supply, given the 4-year time horizon of the auction and the real financial pressures facing generators. Every T-4 auction will require a lasting and satisfactory solution to locational issues ensuring that any restrictions on generator bids are compatible with long term incentives and do not deny the ability to earn the required revenues to continue operating.

Proposals giving preferential treatment to new entrants in constrained areas

We are very surprised by the proposals in the Consultation Paper "to allow multi-year pay-as-bid Reliability Options to participate within a constrained area" given the European Commission's understanding in the State aid decision that grid constraints were temporary and would be resolved to a large extent by 2024 and that I-SEM market reforms would afford additional revenues to plant behind the constraints. Clearly that is not the case.

(1) The proposals clearly imply that the constraints are enduring, or at least more than temporary (as indicated to the European Commission), since only then would there be any reason to offer long term contracts to new entrants in constrained areas.

(2) The desire to facilitate new entry clearly indicates that constrained areas – and the Dublin area in particular – are not in a position of excess supply. Otherwise there would be no reason to contemplate contracts intended to make entry easier.

(3) As a corollary, the unconstrained part of the market must have a surplus of lower cost generation, or else new entrants would not need to be constrained on in the capacity market.

(4) Market conditions therefore differ significantly between constrained areas and the rest of the market – this is something the market arrangements need to recognise.

The EC noted the importance of locational signals for incentivising generation and transmission capacity in areas of constraints but yet we see no market reforms to address these concerns. Instead, the proposal is to pay new entrants in constrained areas a high price for the next 10 years, whilst sending existing capacity in the same areas a strong signal to exit by imposing upon them lower bid limits which deny their ability to earn sufficient revenues to continue operating even though they may be the lowest cost solution to the constraints.

Efforts that facilitate such new entry would artificially prolong the general state of excess capacity in the notional unconstrained market, delaying even further the (already distant) prospect of high (but short lived) capacity prices. It would also be an inefficient way to resolve constraints, unnecessarily raising costs to consumers and would put security of supply at risk by introducing the possibility of delays in construction. We thus reject Options 2 and 3 as proposed in the consultation paper to facilitate new entry in constrained areas and strongly suggest that the SEM Committee should re-focus its efforts on reforms needed to enable existing capacity in constrained areas to remain open where they represent the lowest overall cost of meeting those constraints.

Reforms needed to enable existing capacity in constrained areas to remain

In relation to the ECPC, we note that it was originally set at 50% Net CONE because the RAs estimated this to be a price above the NGFC of most capacity required to meet the Capacity Requirement. In their analysis, the RAs used Non-Fuel Operating Costs (NFOC) from historical generator financial reporting as a proxy for Fixed Operating Costs in the NGFC formula. However NFOC does not include the capital requirements and costs of financing operations on an ongoing basis. It will therefore be necessary to reset ECPC to include the capital requirements of plants going forward.

In relation to setting the Unit Specific Price Cap (USPC), we wish to draw to the attention of the SEM Committee fundamental problems that are not flagged in the Consultation Paper, but which we have raised at various times.

- First, the concept of Net Going Forward Costs (NGFC) is too narrowly defined. The cost of continuing operations at a generator includes the capital requirements and costs of financing operations on an ongoing basis. We provide an expert report from KPMG supporting this fact in a Confidential Addendum.
- Second, the bidding process for multi-unit generators is too inflexible to cope with the shared costs of operation. The auction needs to include some basis for recognising that forward-looking shared costs (e.g. the cost of managing a power station) persist as long as one unit remains in operation, even if one or more of the other units close down if they are not successful in the auction.
- Third, in relation to plant constrained-on in the capacity market operating in conditions of general excess capacity at the notional unconstrained system level, limiting the prices paid to NGFC is inefficient, uncompetitive and discriminatory.

Provision for Unavoidable Future Investment (UFI) through the USPC process as implemented by the SEM Committee is also not fit for purpose. It patently does not facilitate significant investment in plant upgrade or refurbishment and is far too risky for generators constrained on in the capacity market to even contemplate as they are exposed to the unmanageable risk over whether constraints will endure for the full period necessary to recover their UFI costs. An alternative solution is urgently required. We therefore suggest introducing a specific category of multi-year Reliability Options with bid limits at APC for plant refurbishment / upgrade, and to have a lower investment threshold for these categories, which we propose needs to be set at €50/kW de-rated capacity. This approach would be in line with the British capacity market rules for refurbishment.

Other key points:

Further points of note which are discussed in greater detail within the response include the following:

- We support the proposal to include transmission constraints within the T-4 auction.
- We note that the process of appraising bids cannot be limited to a comparison of capacity prices when the relevant plants are reimbursed on a pay-as-bid basis (i.e. if it is constrained on) in both the capacity market and the energy market. In such cases, efficient selection of the plant with the lowest total costs (including capacity and energy) requires an appraisal process that simultaneously considers both capacity bids and energy costs. A CRM selection process that only considers capacity bids will bias the choice in favour of plants with a low capacity bid but very high energy costs, and will not act in the interests of consumers.
- The TSOs proposed AASM for implementing the new auction format is fundamentally flawed because (a) it does not prioritise shorter-term contracts in meeting constraints and (b) the proposed calculation of Net Social Welfare does not accurately reflect the costs and benefits of selecting offers from constrained plant.
- We propose that at least an additional 350MW of capacity be procured in the T-4 auction through a combination of incorporating operating reserves and a tightening of the Loss of Load Expectation (LOLE) standard.
- We oppose withholding capacity procured in the T-4 auction for the corresponding T-1 auction, particularly in constrained areas. This will artificially lower T-4 auction prices and discourage new entry by reliable generation, in favour of less reliable DSU capacity.
- In addition to changing the definition of NGFC to include the capital requirements and costs of financing operations on an ongoing basis we also suggest amending the Auction Price Caps to account for the greater level of uncertainty over future costs and incomes due to looking four years ahead for the T-4 auction and in the case of the ECPC to allow for a competitive clearing price which is not currently the case.
- We recommend keeping Administered Scarcity Price (ASP) at existing levels to mitigate excess risk for participants and defer any decision to increase ASP towards Value of Loss Load (VoLL) until we have a tested and proven secondary market.
- We continue to express significant concern about the overall approach to the LCC methodology and the apportionment of Dublin demand.

1. Introduction

This document sets out Energia's comments in response to the Consultation Paper on the 2022/23 T-4 Capacity Auction Parameters ("the Consultation Paper")[1], including answers to the questions posed within that paper.

In response to consultation SEM-18-009 covering the T-1 auction parameters for CY2019/20, we submitted an expert Memo from NERA[2] (the "NERA Memo"). It is disappointing that the SEM Committee, in its subsequent decision paper SEM-18-030, did not respond to the NERA Memo whatsoever, particularly given the fundamental importance of its content. It remains highly pertinent to the T-4 auction parameters and is therefore re-submitted along with this response in the expectation that it will be duly considered[3].

Also in support of this response we submit an confidential expert report from KPMG and trust this will be given the serious consideration that it merits.

Energia would welcome the opportunity for a meeting with the RAs about this response and its accompanying expert reports.

As a preliminary comment we note that this consultation takes place at a time when the necessary modifications to Generators' Licences have not been made, and proposed modifications are the subject of ongoing proceedings, which are directly relevant to the issues set out in the Consultation Paper. We are of the firm view that prior to any progress being made in respect of further auctions, the matter of the conditions to which Generators will be subject when participating in the I-SEM, including as regards the revenues which they can earn from all relevant markets (including for energy, system services and capacity) must be resolved. All of our comments in response to the Consultation Paper are strictly without prejudice to this fundamental position and must be read in its context. In these circumstances, we do not believe it is appropriate that further auctions be progressed pending the necessary modifications to the Generation Licence conditions.

The remainder of this response is structured as follows. Section 2 provides our overarching comments and section 3 responds to the consultation questions. This response is also supplemented a confidential addendum submitted separately ("the Confidential Addendum") and referenced where applicable.

[1] Consultation Paper "Capacity Remuneration Mechanism Parameters for T-4 2022/23 Capacity Auction", SEM-18-028, 14 May 2018.
[2] NERA Memo to Viridian, 'Competition and Cost Recovery under the 2019/20 T-1 Capacity Auction Parameters', 19 April 2018.
[3] It is equally regrettable that the SEM Committee did not refer to or engage with related and other issues raised by Energia in its response to SEM-18-009, most of which remain relevant in the context of this consultation. We therefore request that the SEM Committee give due consideration to that response in conjunction with this one when determining the appropriate regulatory framework for the first T-4 capacity auction for CY2022/23.

2. Overarching Points

The overarching points Energia wishes to raise in this response are discussed below under five headings.

2.1 Auctions Need to Allow Competitive Market Pricing

The T-1 auction rules presumed that the market clearing price would equal the (narrowly and incorrectly defined) forward-looking costs of the marginal provider in conditions of excess supply, and that only new entry should raise prices any higher, namely to the cost of new entry. This view is incorrect and incompatible with competitive pricing. In fact:

- new entry expands supply, and must therefore *lower* prices from a previously higher level;
- in competitive markets, prices rise above the forward-looking costs of the current providers when there is a shortage, i.e. *before* new entry occurs;
- when there is a shortage, competitive prices may even exceed the cost of new entry for a while.

These observations are directly relevant to the rules for generators constrained-on in the capacity market, located where *by definition* there is no excess supply. If such constrained-on generators cannot cover their forward-looking costs (including the costs of investing to maintain capacity and the cost of financing continuing operations), they must close, and the grid will be short of capacity within the constrained area. In conditions where services are in short supply and are remunerated on a pay-as-bid basis, a competitive *market* price is not defined by price caps which limit *bid* prices in a pay-as-clear auction, based on Net Going Forward Costs (NGFC). The concept of NGFC is deficient in two important respects:

- First, the full range of costs efficiently incurred by continued operations is wider than the definition of NGFC chosen by the SEMC and includes the costs of financing operations, and/or some other allowance for risk.
- Second, in shortage conditions, competitive market outcomes provide an opportunity to recover the sunk costs of past investments.

The pricing rules used in the T-1 auction for 2018/19 were therefore incorrectly defined and provide insufficient incentive for constrained on generators in the capacity market to continue operation – indeed the current auction pricing rules make it impossible for some constrained-on generators to finance continued operations or to capture a reasonable, competitive market price for their services.

We conclude (1) that the caps on bid prices need to be amended to include a wider range of forward-looking costs than allowed in the T-1 auction, and (2) that the rules for setting prices actually paid to constrained-on generation in the capacity market should not refer to the caps on bid prices for a pay-as-clear auction in a notional unconstrained market in excess, but should instead permit higher prices, closer to the competitive market outcome as described above.

2.2 Auction Format and Multi-Year Bids

Under section 3, question (1) of the Consultation Paper, the SEM Committee asks (1) whether procurement of out-of-merit Reliability Options for locational reasons should displace in-merit capacity (instead of being an additional requirement) and (2) whether to allow new capacity seeking a multi-year pay-as-bid offer to compete for a pay-as-bid Reliability Option up to at least the value of Net CONE.

We have no issue with the first of these changes, in principle, since it is required by the State aid process (and since changing the method of handling transmission constraints will not solve the fundamental inadequacy of the remuneration for constrained-on plant).

However, we are very surprised by the second proposed change given the European Commission's understanding in the State aid decision that grid constraints were temporary and would be resolved to a large extent by 2024[4] and that I-SEM market reforms would afford additional revenues to plant behind the constraints.

The second proposed change will bias the selection of capacity towards multi-year contracts, i.e. in favour of new entry, even when the new entry prompted by multi-year contracts would be inefficient and would raise costs for consumers, relative to using existing capacity. The bias in favour of new entry will also introduce the possibility of delays in construction putting security of supply at risk.

See our comments under section 3 below for detailed reasoning behind this conclusion and alternative suggestions.

The SEM Committee itself recognises this danger in paragraph 2.2.9 of the Consultation Paper and again in paragraph 3.4.8, where the SEM Committee asserts without explanation that the risk of stranding is higher for "out-of-merit lumpiness solutions" than for solutions to transmission constraints. However, that does not negate our finding: behind transmission constraints, apparently low-priced multi-year contracts are likely to prove unnecessarily expensive and to become stranded.

This flaw is a likely outcome of adopting Options 2 and 3, which let multi-year bids compete directly with single-year bids, since they focus the selection of bids primarily on capacity price. The approach to lumpiness may compound the error, by favouring more expensive offers with long durations whose volume happens to match the capacity constraints in preference to lower priced offers of shorter duration whose volumes exceed the capacity constraints. Such outcomes would be highly inefficient.

Ultimately, we conclude that "Option 1" (using multi-year contracts only when single-year bids are insufficient) with some modification, is the only transparent and predictable way forward, with the best chance of giving the efficient outcomes that are in consumers' interests.

Option 1 requires some modification. The efficiency of outcomes under this option will be enhanced by removing discriminatory access to higher priced multi-year Reliability Options. (See our response to section 2 question 3.)

[4] State aid No. SA.44464 (2017/N) – Ireland Irish Capacity Mechanism, para 155.

2.3 Withholding Demand from T-4 Auctions

Under section 6, question (1), the SEM Committee asks if the proportion of demand held back from the T-4 CY2022/23 auction for the T-1 CY2022/23 should be increased. We find that the reasons for favouring such an increase are invalid and that such a move would be incompatible with other auction rules and so would have adverse consequences for consumers.

In the first place, the current bidding rules require all existing generators to enter the T-4 auction. Holding back (any) demand for later auctions therefore creates a fundamental distortion. Withholding demand whilst forcing supply will cause the T-4 auction price to be permanently depressed by over-supply, whilst the T-1 price is permanently elevated by the lack of capacity available to enter the auction. This outcome would be artificially sustained (by the prohibition on arbitrage between auctions) and is also anti-competitive. Artificially lowering T-4 auction prices would discourage new entry by reliable generation, in favour of less reliable DSU capacity. Whilst that concern may not arise at the notional unconstrained system-wide level for some years to come, it is already a problem for constrained areas, where the need for planning ahead is more acute.

Second, DSU capacity is highly unlikely to be sufficiently reliable to meet the TSO's needs for system support. The TSO has a requirement to contract for reliable capacity in constrained areas, well in advance. Concrete planning standards therefore militate against favouring the short-term procurement of DSU capacity. In any case, much of the so-called DSU capacity will be provided by back-up generators (rather than interruptions to demand), which have the same planning timescales as any other generators, so they do not need special access to T-1 auctions.

In summary, we conclude that it is wrong to link the level of demand in the T-4 auction to the level of DSU capacity (or DSU bids), because the TSO planning criteria are more relevant and important. The TSO will be particularly concerned with securing supplies in advance within constrained areas, and that withholding demand from the T-4 auction will undermine the ability to do so. Furthermore, the price-depressing effect of withholding demand at T-4 provides a signal to encourage exit, which is not desirable within constrained areas, and should be focused within areas with excess supply.

It should also be noted that the results from the first T-1 auction, referred to and relied upon in paragraph 6.2.3 of the Consultation Paper, should be disregarded entirely as the DSU volume was artificially elevated in that auction, as confirmed in decision paper SEM-18-030[5] and as further discussed in our response to SEM-18-009 and the Confidential Addendum.

[5] Decision paper SEM-18-030 will result in the de-rated capacity of DSUs being significantly reduced in future auctions to reflect their run-hour limitations and also remedied a serious oversight in the first auction which put the long stop date after the end of the period for which new DSUs were contracted to deliver capacity, which created 'inappropriate incentives' according to the SEM Committee.

2.4 Bid Price Caps

Section 7 poses a question about each of the three bid price caps: APC; ECPC; and USPC. In relation to each, we note that, at a general level, there is more uncertainty over future costs and infra-marginal rents when looking four years ahead than at a T-1 auction. To ensure that Reliability Options remain compatible with future costs of operation, the allowances for all relevant costs need to include a higher margin for error in the T-4 auction than in the T-1 auction. This higher margin for error should be the subject of further consultation.

- The ECPC was originally set at 50% Net CONE because the RAs estimated this to be a price above the NGFC of most capacity required to meet the Capacity Requirement. In their analysis, the RAs used Non-Fuel Operating Costs (NFOC) from historical generator financial reporting as a proxy for Fixed Operating Costs in the NGFC formula[6]. However NFOC does not include the capital requirements and costs of financing operations on an ongoing basis.. It will therefore be necessary to reset ECPC to include the capital requirements of plants going forward.

In relation to setting the USPC, we wish to draw to the attention of the SEM Committee certain other problems that are not flagged in the Consultation Paper, but which we have raised at various times.

- First, the concept of Net Going Forward Costs (NGFC) is too narrowly defined. The cost of continuing operations at a generator includes the capital requirements and costs of financing operations on an ongoing basis.
- Second, the bidding process for multi-unit generators is too inflexible to cope with the shared costs of operation. The auction needs to include some basis for recognising that forward-looking shared costs (e.g. the cost of managing a power station) persist as long as one unit remains in operation, even if one or more of the other units close down as a result of being unsuccessful in the auction.
- Third, in relation to constrained on plant (who are operating in conditions of general excess capacity in the notional unconstrained market at a system level), limiting the prices paid to NGFC is inefficient, uncompetitive and discriminatory.

We provide the detailed reasoning behind these conclusions in section 7, question 3 below.

We also note that the process of appraising bids cannot be limited to a comparison of capacity prices when the relevant plants are reimbursed on a pay-as-bid basis (i.e. if it is constrained on) in *both* the capacity market *and* the energy market. In such cases, efficient selection of the plant with the lowest total costs requires an appraisal process that simultaneously considers both capacity bids and energy costs. A CRM selection process that only considers capacity bids will bias the choice in favour of plants with a low capacity bid but very high energy costs, and will not act in the interests of consumers.

[6] See SEM Committee Decision SEM-18-022.

2.5 New Capacity Investment Rate Threshold (NCIRT)

Section 9, question (1) refers to the level at which to set NCIRT for the T-4 CY 2022/23 auction. However a key issue not addressed in this section is that NCIRT effectively rules out existing generators planning a substantive refurbishment or upgrade. This is a new build threshold only.

There are compelling reasons to introduce a specific category of multi-year Reliability Options for plant refurbishment / upgrade, and to have a lower investment threshold for these categories, which we suggest needs to be set at €50/kW de-rated capacity. Once this threshold is met, bid limits should then be set at APC automatically in line with the GB rules for plant refurbishment.

Given its lack of long-term security along with other restrictive qualifying conditions, the UFI mechanism is not fit for purpose and is discouraging investment to prolong the life of existing plant and rules out investments to enhance their efficiency or provision of system services for example. The current rules thus favour constructing new plant, even when that would be less efficient and more expensive for consumers. The possibility of delays in the otherwise unnecessary construction of new plant also puts security of supply at risk.

The introduction of a specific category of multi-year Reliability Options for plant refurbishment / upgrade is thus necessary to level a playing field which currently slopes significantly towards inefficient investment in new plant, which puts security of supply at risk.

3. Response to Specific Consultation Questions

Section 2. Treatment of Constraints in T-4 Auction

1) Do you agree with the SEM Committee's proposal to reflect transmission constraints in the T-4 auction? Please explain your rationale.

We support the proposal to include transmission constraints within the T-4 auction, for a number of reasons.

The State aid decision of the European Commission seems to require that the auction take transmission constraints into account as much as possible. A certain amount of generation needs to be secured in a constrained area, to meet all constraints requirements for that area. Capacity procured through the T-4 auction will displace other generation, thereby avoiding "over-procurement". If transmission constraints are not included in the CRM, then more local generation will have to be procured through other means (and will not displace other generation). This will create additional over-procurement, contrary to the objectives set out in the State Aid decision.

Transmission constraints look likely to persist until the first T-4 auction (and indeed for some years thereafter). The Dublin area is significantly constrained at present, and very high demand growth in the area (as indicated in several EirGrid and regulatory publications) implies that the constraints will continue and indeed tighten (pending significant investment in the network)[7]. Transmission constraints in other areas (e.g. around Northern Ireland) may also remain significant for many years to come. The T-4 auction therefore needs to recognise the likelihood of these conditions.

As explained in previous submissions (most recently in response to SEM-18-009), the overall approach to the LCC methodology and the apportionment of Dublin demand continues to be of significant concern. There will remain a substantive gap between the locational capacity requirements identified in the CRM auction and the full generation requirements needed to meet all network constraints, because the auction will, at best, only recognise constraints on "power transfer" (MW flows). Many local generation requirements are driven by the need for stability (MW reserves), voltage control (MVAr), and other technical factors.

For the period that the gap continues and as long as regulatory restrictions in the capacity market prevent cost recovery, there is a substantial and imminent risk to security of supply as the available mechanisms do not collectively address the security requirements.

Therefore, some "bilateral contract" or "Targeted Contract Mechanism" will inevitably be required to deal with transmission constraints.

[7] See Confidential Addendum for more details.

2) Do you have any comment on the possible inclusion of multi-year pay-as-bid Reliability Options to meet the minimum Locational Capacity Constraint requirement?

Prices in multi-year contracts are not directly comparable with prices in single-year contracts.

We have pointed out previously that the prices in multi-year contracts are not comparable with the prices in single-year contracts. In particular, a long-term contract can be a more expensive solution than a single-year contract with the same price or even a higher one. A high single-year price may not last for long; it may be followed by years of low prices, e.g. if a local or national shortage arises but is then eliminated by investment in the grid. A multi-year contract which persists after this collapse in short-term prices would be more expensive. Paragraph 2.2.9 of the consultation document explicitly recognises these possibilities.

The capacity auction will therefore produce inefficient and higher cost outcomes, if the prices bid for multi-year contracts are compared directly with the prices bid for single-year contracts. Any efficient selection process must also consider the total costs of constrained-on plant (including capacity and energy) as discussed further below.

3) Do you have a preference between the options set out above in relation to pay-as-bid offers? Please explain your rationale.

Options 2 and 3 are flawed and will produce inefficient, high cost outcomes.

Both Option 2 and Option 3 allow multi-year pay-as-bid Reliability Options to compete against single year offers on the basis of price, without recognising the costs of the long-term commitment. These options will produce biased and costly outcomes in favour of new entry, which also introduces the possibility of delays in construction putting security of supply at risk.

We therefore conclude that only Option 1 (with some modifications) will meet the standards of good regulation and promote anything approaching an efficient outcome that it is in the interests of consumers.

Only a modified Option 1 provides a transparent and fair treatment of multi-year bids.

Of the proposals set out in the Consultation Paper, Option 1 does not require consideration of multi-year bids unless "there are no other solutions available to satisfy the minimum MWs in the constrained area". We presume this means that all single-year bids would be accepted first, with only the remaining balance of the requirement being made up from multi-year bids. That would avoid any comparison of single-year and multi-year bids.

We therefore conclude that only Option 1 provides a transparent and fair treatment of multi-year bids, however it should be amended as suggested below.

Option 1 should be modified to promote competition and to facilitate comparison of bids

To promote competition, Option 1 should be adapted, so that existing generators can earn the same revenue as new entrants, (1) by allowing all existing generators within a constrained area to bid up to the market-clearing price for single-year offers in that area (i.e. by lifting their price cap to the Auction Price Cap),[8] and (2) to submit multi-year offers as well as single-year offers. These amendments would improve competition and also facilitate price-based comparison of bids.

As we understand it, even under Option 1, the auction would require some method for choosing between multi-year bids with different durations. Generalising the principle behind Option 1, we would propose that the auction consider first single-year bids, then two-year bids, then three-year bids, and so on up to ten-year bids, if necessary.[9] The selection process would stop when the capacity requirement was met by the contracts with the shortest possible duration. For the final contract duration needed to meet the capacity requirement, selection of competing bids can be based on a simple comparison of bid prices.

This approach is more rational than that proposed in Appendix A to the Consultation Paper, whereby single-year and multi-year bids would first be ranked by price, then by several other criteria, and only finally by duration. That approach is almost certain to raise costs unnecessarily and to create stranded costs for the consumer. (See below for further comments on this matter.)

Any efficient selection process must consider the total costs of constrained-on plant.

We note one further complication relating to constrained-on plant. If a plant sells its energy output at a market-clearing energy price (i.e. “in-merit”), its capacity bid can be appraised simply by considering its capacity bid price. If such plants earn an infra-marginal rent due to a low cost of generating energy, it will be reflected in a low *net* cost of capacity; low capacity bids therefore indicate low total costs.

That condition does not apply when the plant is reimbursed on a pay-as-bid basis (i.e. if it is constrained on) in *both* the capacity market *and* the energy market. In such cases, efficient selection of the plant with the lowest total costs requires an appraisal process that simultaneously considers both capacity bids and energy costs. A CRM selection process that only considers capacity bids will bias the choice in favour of plants with a low capacity bid but very high energy costs, and will not act in the interests of consumers.

Section 3. Auction Format

1) Do you have any comments on the SEM Committee’s proposal to move to an auction format based on Auction Format C for the CY2022/23 T-4 auction, following the State aid decision?

In paragraph 3.1.23, the Consultation Paper gives two reasons for changing the auction format:

---

8 For the system-wide auction, the pricing rule allows existing plant to be paid the clearing price, which rises to the level of new entrant costs when new entry occurs. That rule falls short of competitive pricing in conditions of shortage, before new entry occurs, but otherwise allows existing plant to be paid the competitive price. The same is not true for constrained-on plant, which are paid-as-bid under the capacity market rules. The market-clearing price in a pay-as-bid market is the highest price accepted. All market participants must bid up to this price in order to earn the same revenue as the marginal unit, and hence the competitive market price.

9 The current auction rules treat two-year bids as equivalent to single-year bids. (See paragraph 3.4.3 of the Consultation Paper.) Given that most transmission constraints will be expected to last at least two years, we believe that this deviation from the principle of Option 1 would have only limited effects on the outcome.

"3.1.2 Two changes are being proposed to the auction design applied to the CY2018/19 auction. The proposals aim to meet the key objectives of:

- **Compliance with the State aid commitments not to over procure:** As part of the State aid process, the authorities in Ireland and Northern Ireland gave an undertaking to the EC that from CY2020/21 onwards, any capacity awarded out-of-merit Reliability Options for locational capacity constraint reasons should not be additional to the capacity secured in merit. Consequently, if out-of-merit volumes need to be procured to satisfy locational constraints, this will displace in-merit generation elsewhere. The CY2022/23 T-4 auction will be the first auction for which this change applies; and
- **Optimise outcome of T-4 auction from assessment of new and existing plant bids:** Changes to the auction format to facilitate the option proposed in Section 2.2 aimed at ensuring the right outcome for consumers when considering bids from existing plant and new plant bids. The option proposed is to allow new capacity seeking a multi-year pay-as-bid offers to compete for a pay-as-bid Reliability Option up to the value of Net CONE."

We have no issue with the first of these changes, in principle, since it is required by the State aid process (and since changing the method of handling transmission constraints will not solve the fundamental inadequacy of the remuneration for constrained on plant).

However, the second proposed change will bias the selection of capacity towards multi-year contracts, i.e. in favour of new entry, even when the new entry prompted by multi-year contracts would be inefficient and would raise costs for consumers, relative to using existing capacity. As noted above, Option 1 is the only transparent and fair approach to addressing the severe disadvantages posed by multi-year contracts (disadvantages which the SEM Committee notes in its Consultation Paper). We cannot therefore support amendments to the auction method based on Option 2, as the resulting selection of capacity will be biased, inefficient and expensive for consumers. Its bias in favour of new capacity would also put security of supply at risk by introducing the possibility of delays in construction.

We discuss below the specific problems arising from Option 2 in relation to the details of the AASM set out in Appendix A.

2) Do you have any comments on the TSOs proposed AASM for implementing the new auction format, as set out in Appendix A, or the RAs' proposed change to the N parameter?

The Consultation Paper does not provide sufficient detail on the design of Option C to support a detailed appraisal of the design. It would be necessary to provide a full draft of the revised capacity market code for both Options C and D in order to identify whether we supported their adoption as currently proposed. In the absence of such detail it is not possible to check thoroughly for errors or to assess the implications of the SEM Committee's proposal.

For instance, the SEM Committee proposes to define a parameter "N" under Option C to limit the size of the combinatorial problem (para 3.3.8). N defines the number of inflexible offers above and below the marginal offer that the TSO will consider as alternatives to the marginal offer. In the main body of the report, the SEM Committee describes N as applying in cases where the marginal offer is inflexible. The example in Appendix A, however, shows the application of the mechanism in the case where a marginal plant is *flexible*. In practice, applying the heuristic algorithm will not result in any gain unless the marginal unit is *inflexible*. (That is, selecting higher-priced offers will only improve social welfare if the set of lower-priced offers does not exactly meet the level of demand procured through the auction.)

Based on the existing detail available in Appendix A, we believe the SEM Committee's proposal is flawed in at least two ways.

Firstly, it is unclear from the SEM Committee's description in Appendix A how the mechanism would take account of contract duration when selecting bids. Appendix A refers to the concept of "Net Social Welfare". The calculation of Net Social Welfare is set out in section F.8.4.2 of the Capacity Market Code. As defined there, it depends only on the price-quantity pair submitted in any bid and on the demand curve.[10] However, any meaningful definition of Net Social Welfare would have to consider costs (including energy costs for constrained on plant) over the whole duration of the bid, or else it would provide biased outcomes that unduly favour multi-year bids. The only reference to duration in Appendix A of the current Consultation comes in the discussion of tie-breakers under section F.4.8.7.c of the Capacity Market Code and even then it only applies after selecting for "Clean" plant.

Given that the proposed mechanism does not prioritise shorter-term contracts in meeting constraints, it is fundamentally flawed. Expensive offers with long durations whose volume happens to match the capacity constraints in the auction would be selected in preference to lower priced offers of shorter duration whose volumes exceed the capacity constraints. As a result, the proposed mechanism would impose excess costs on consumers.

Secondly, the SEM Committee proposes to select the efficient plant to meet constraints using a calculation of Net Social Welfare that does not accurately reflect the costs and benefits of selecting offers from constrained plant. Constrained plant will from time to time operate in pay-as-bid markets for both capacity and energy. The total cost of such plant, and hence its impact on Net Social Welfare, depends on the payments for both capacity and energy (when called upon to generate). Considering only the capacity bid will lead to biased choices and invalidate any claim to be maximising Net Social Welfare. The selection of constrained-on plant therefore needs to consider both the prices bid for capacity and the prices that would ultimately be paid for the energy produced by that capacity.

3) Do you have any comment on the proposed change to the format to accommodate multi-year pay-as-bid Reliability Options?

[10] Under the CMC, paragraph F.8.4.3 and F.8.4.4, shorter-duration contracts are given preference to longer-duration contracts for meeting constraints. However, the current Consultation Paper does not refer to these restrictions and only to the concept of Net Social Welfare.

In the Appendix describing the AASM, the current proposal applies Option 2 to the appraisal of multi-year contracts.[11] Specifically, the current proposal contains the following rule:

> "2. Where two or more offers have the same price (i.e. there is a tie), schedule offer pairs in the following order: clean, flexible, quantity (lesser quantities first), duration (shorter durations first), random."[12]

This rule treats single-year and multi-year offers as equivalent in price terms at first, with duration coming last in the selection criteria. However, price is a very unreliable guide to the relative merits of bids with different durations. This section of the rules should therefore be amended to apply Option 1, with bids being ordered first by duration (from shortest to longest), ranked by price *for each duration*, and then selected by reference to the other criteria ("clean, flexible, quantity") only if is there is a tie.

In paragraph 3.4.7, the SEM Committee claims that "the benefits of accepting a multi-year pay-as-bid Reliability Option *in preference to another more expensive offer* in the same under-supplied area are potentially significant". This statement is likely to be untrue in a wide range of circumstances - that in fact a multi-year bid will be more expensive than short-lived use of a single-year bid with a higher price.

The SEM Committee should be very wary of accepting multi-year bids in preference to single-year bids at the same or even higher prices, because of their higher total cost to consumers. Option 1 is the only approach that does not bias the choice in favour of multi-year bids.

The SEM Committee recognises the potential to select expensive multi-year contracts in paragraph 3.4.8, but primarily in relation to the method of dealing with lumpiness. It asserts that "[w]hilst the same is true in principle for solving transmission constraint, it appears more likely that the risk of stranding is higher for out-of-merit lumpiness solutions." The SEM Committee provides no explanation for this statement, but it does not in any case negate our finding: behind transmission constraints, apparently low-priced multi-year contracts are likely to prove unnecessarily expensive and to become stranded at the consumers' expense.

Section 4. Capacity Requirement

1) What are your views on the potential changes proposed to the CR methodology i.e:

- Incorporate some measure of operating reserves in the CR? What MW value?

- Whether the 8-hours LOLE standard should be tightened (reducing the LOLE target). What level do you consider to be appropriate and why?

In section 4.3.9 of the Consultation Paper, the SEM Committee suggests five options for the amount of operating reserve to be added to the CR. Considering operating reserve in strict isolation of other factors, there are good reasons to support MW figures akin to Options 4 and 5. Certainly, Option 1 (100 MW) would be insufficient. Adding only 100 MW would mean that in principle (and assuming that all other

[11] SEM-18-028, 14 May 2018, paragraph 3.4.5.
[12] SEM-18-028, 14 May 2018, Appendix A, page 72.

parameters are set appropriately), that operating reserve is reduced to 100 MW for 8 hours of the year. However if this is the case, there will be many more hours where the operating reserve will be more than 100 MW, but less than normal operating reserve levels. During these hours, the system is exposed to risks of low-frequency events and unplanned under-frequency load shedding, for loss of a single in-feed (generator or interconnector).

We agree with the point made in section 4.4.3 of the Consultation Paper, that *"any moves to incorporate operating reserve should be considered in conjunction with the potential harmonisation of an LOLE or equivalent standard".* Increasing the CR to reflect a "tighter" LOLE standard, will also tend to increase the amount of operating reserve available for dispatch.

Taking both factors combined, we note the suggestion in section 4.3.7 of the Consultation Paper; i.e. increasing the CR by 350 MW, to recognise the need for (a) 100 MW of operating reserve, and (b) an additional 250 MW required to adopt the equivalent of an LOLE standard of 3 hours per year. This is our preferred option. These additional items truly form part of the capacity requirement:

- Even in the event of demand shedding, the TSO must retain a minimum amount of reserve for frequency control and system security reasons. The inclusion of 100 MW of operating reserve is therefore required to represent the minimum level of capacity before the TSO starts shedding demand (i.e. before any operating reserve is being drawn upon and, clearly, not at 0 MW reserve).
- It is also appropriate to include a further 250 MW in the CR to reflect a 3-hour LOLE standard, to harmonise standards with neighbouring markets in Europe.
- As stated in section 4.1 of the Consultation Paper, any additional margin resulting from the design of the transitional auctions will no longer be available as an inherent "buffer" for the T-4 auction.

Further, there is a strong case for introducing these elements progressively from the T-1 2019/20 transitional auction onward, to offset the gradual changes listed in section 4.1.7 of the Consultation Paper:

(1) no additional capacity procured for transmission constraints;

(2) the use of a future year demand forecast; and

(3) exit by some of the excess supply of capacity.

These changes will substantially tighten supply and/or lower the demand curve (though not actual demand) by anything from 825 MW to 1,350 MW relative to the figures used for 2018/19. Introducing the measures progressively over the transitional period would improve stability and provide a smoother transition to the first T-4 auction.

Section 5. Administered Scarcity Pricing (ASP) Parameters

1) Which of the options for the value of Full ASP do you consider most appropriate for the first T-4 capacity auction, and why?

Energia has considered each of the options put forward in section 5.3.1 of the Consultation Paper in respect of the Full ASP for the first T-4 capacity auction and recommend that Option A is used to set Full ASP for this auction i.e. 25% of VoLL, which is expected to be €3,000/MWh. This is in line with the current level of Full ASP that has been used in the transitional capacity auctions to date. We have outlined the reasons why we consider Option A to be the most appropriate level of Full ASP for the first T-4 capacity auction below.

Impact of ASP on system security

Energia notes that the current Full ASP of €3,000/MWh used in the transitional auctions was in line with the GB Full ASP. However the GB Full ASP is set to increase to €6,000/MWh from 1st November 2018. The Consultation Paper outlines a potential impact of maintaining I-SEM Full ASP at the current level and therefore below the GB Full ASP, as an increased likelihood for power flows from I-SEM to GB during times of scarcity and as such reducing I-SEM system security.

However a key difference to note is that the ASP in GB is a price cap whereas in I-SEM it is a price floor. Therefore in a scarcity event the Balancing Market price will be the higher of the ASP function price or a market determined price up to VoLL (currently set at €11,128.26/MWh).

Given this key differential Energia does not see any requirement for the Full ASP in I-SEM to mimic the Full ASP in GB. In addition there is no operational experience of I-SEM yet and therefore any supporting evidence to increase the current ASP value. Therefore further consideration to transition to a higher ASP for future auctions should be deferred until there is justifiable evidence from an operational market.

Secondary trading and risk management

As noted in our response to Consultation Paper SEM-15-014, given the significant risks that are imposed on CRM participants through ASP, it is essential that a functional secondary capacity market is developed to enable participants to manage their exposure during planned or forced outages. Consideration cannot therefore be given to increasing Full ASP towards higher levels of VoLL(i.e. 50% or 100% as outlined in options B & C) until the following requirements to facilitate risk management have been achieved:

1) A liquid, transparent, exclusive and fully functional IDM to allow participants to appropriately manage exposure to energy imbalances;

2) A liquid, transparent, exclusive, centralised secondary market for ROs, with appropriate and effective market power mitigation measures, including volume obligations on dominant participants, to allow generators to manage their financial exposures associated with planned and forced outages;

3) A liquid, forward contract market allow suppliers and generators to hedge their residual exposures up to the RO strike price;

4) Exemptions from RO cash outs for generators that are available but not dispatched at times of scarcity;

5) Appropriate stop loss limits to protect existing participants from bankruptcy and to remove potential barriers to financing for new investment.

Currently each of these requirements are either untested, unproven or non-existent. Accordingly any decision to increase ASP towards a higher level of VoLL should be deferred. The impact of any increase in ASP whilst the above requirements are not met is likely to be in the form of higher CRM bids in the T-4 auction as generators seek to protect themselves from increased risk, thus resulting in a higher CRM clearing price and ultimately higher CRM bills for end consumers.

2) Should we move to setting VoLL on an October to September year, rather than the current Calendar Year basis, so that a single value of VoLL pertains within a Capacity Year?

Energia are supportive of the move to set VoLL on an October to September to align with a Capacity Year rather than on a calendar year basis. The key benefit of this proposal is that ASP will not change part way through a Capacity Year and therefore provides a greater level of certainty for CRM participants when participating in the capacity auctions.

Section 6. Auction Volumes and Demand Curves

1) Should the proportion of the CR the SEM Committee hold back from the T-4 CY2022/23 auction for the T-1 CY2022/23 be increased from 5% to 7.5%, and why?

Given the restrictive bidding rules, which require all generators to enter the T-4 auction, holding back demand for later auctions creates a fundamental distortion. Withholding demand whilst forcing supply imposes excess supply, causing the T-4 auction price to be permanently depressed, whilst the T-1 price is permanently elevated by the lack of capacity able to enter the later auction. This outcome would be artificial and anti-competitive, because generators would not be allowed to arbitrage between the two markets by transferring their capacity from low-priced T-4 auctions to high-priced T-1 auctions.

Given this likely distortion in auction prices, imposing T-4 bidding obligations on generators and not on DSUs would be discriminatory, since it would force generators to accept lower auction prices than DSUs, for no good reason. Moreover, by unduly favouring DSUs that are more expensive overall (taking energy and capacity costs into account) and likely to be less reliable than generators, this proposal would raise costs, undermine security of supply, hinder competition and harm consumer interests.

This distortion in the bidding rules and auction prices was exacerbated recently by two unfortunate features of the recent T-1 auction, which led to an overstatement of available DSU capacity. The RAs have recognised these problems and have proposed to remedy them in time for the next T-1 auction:

- First, a drafting error set the “long-stop” date for compliance with the terms of a Reliability Option *after* the period to which the Reliability Option applied. This error gave new DSUs a “free option” to participate in the auction without any penalty for failing to deliver the new capacity – an "inappropriate incentive", as the RAs have pointed out.[13]

- Second, the de-rating factors available to DSUs failed to recognise their run-hour limitations which are now considered to have been too generous. This has now been amended based on average parameters for storage and therefore DSU capacity will be de-rated to a greater extent in future auctions although no evidence to support the new proposed levels is presented.
- Both these factors would have led to an overstatement of the true level of new and existing DSU capacity able to participate in future auctions.[14]

The level of DSU bids seen in the most recent T-1 auction therefore provides a thoroughly unreliable and overstated estimate of the level that will be seen in the next T-4 auction – let alone to the amount of demand to be withheld.

According to the Consultation Paper, the SEM Committee is aiming to help DSUs who cannot be certain of their availability in four years' time.[15] However:

- that criterion is not limited to DSUs, since many generators are unsure of their availability in four years' time;
- some DSUs may be able to commit four years in advance (e.g. if the supposed DSU is actually a back-up generator);
- the capacity of DSUs likely to participate in future auctions may not be indicated by the level of DSUs present in the first T-1 auction; and
- the level of participation by DSUs does not correspond to their likelihood of being selected.

In fact, a more relevant and important question is what level of certainty over availability is required by the TSO (and by potential capacity providers), so that they can plan four years ahead. The need of the TSO dictates a higher level of demand in the T-4 auction than the narrow concerns of certain DSUs.

Leaving aside the weakness of the SEM Committee's arguments, there are in fact good reasons to avoid giving excessive advantages to DSUs.

The Consultation Paper suggests that withholding capacity would facilitate the participation of "environmentally friendly demand side response".[16] Even if demand-side management is seen as good for the environment, since it reduces energy consumption, in practice many DSUs are aiming to provide capacity by installing small back-up generators that are fossil-fired (specifically, distillate- or diesel-fired). These DSUs would not offer any environmental benefits over capacity that is formally provided by generators.

Recent experience highlights the real and significant concern over the reliability of DSUs, over and above that reflected in their de-rating factors. The current de-rating factors of DSUs are based on operational data for energy storage. We highlighted in our earlier submissions (see especially Energia response to SEM-18-009) the

[13] SEM-18-030, *Capacity Remuneration Mechanism (CRM): 2019/20 T-1 Capacity Auction Parameters and Enduring De-rating Methodology – Decision Paper*, 01 June 2018, paragraph 4.1.4.
[14] SEM-18-030, *Capacity Remuneration Mechanism (CRM): 2019/20 T-1 Capacity Auction Parameters and Enduring De-rating Methodology – Decision Paper*, 01 June 2018, page 3.
[15] SEM 18-028, 14 May 2018, paragraph 6.2.1.
[16] SEM 18-028, 14 May 2018, paragraph 6.2.5.

potential overstatement of DSU capacity that would result from such a policy. Providing advantageous terms for DSUs will only exacerbate these distortions to the market.

Indeed, the policy of linking the demand in T-4 auctions (negatively) to the volume of DSU capacity will have deleterious and counter-productive effects in the long term. The more DSUs participate in T-1 auctions, the greater the volume that will be removed from demand in T-4 auctions. Cutting down this demand (whilst forcing all existing generators to bid in T-4 auctions) would cut down opportunities for new entry through investment in generation. The price-depressing effect of withholding demand from the T-4 auction will discourage new entry, thereby limiting the supply of reliable capacity in the long term.

Encouraging new entry was one of the original reasons for having a T-4 auction, as it gave time for construction of new plant. However, withholding 7.5% will reduce the CR of the T-4 auction by more than 500 MW. According to the GCS2017, this amount is the equivalent of some eight years' growth (based on Median scenario). Withholding demand to that extent would therefore delay the prospect of new entry into generation by roughly eight years.

In summary, we conclude it is wrong to link the level of demand in the T-4 auction to the level of DSU capacity (or DSU bids), because TSO planning criterion are more relevant and important.

We also note that withholding demand from, whilst forcing supply into, T-4 auctions will: distort auction prices (lowering them at T-4, raising them at T-1); favour less reliable DSUs (undermining system security); and discourage new entry by reliable generation (raising costs, undermining system security, hindering competition and harming consumer interests).

Finally, it should be noted that the results from the first T-1 auction, referred to and relied upon in paragraph 6.2.3 of the Consultation Paper, should be disregarded entirely as the DSU volume was artificially elevated in that auction, as confirmed in decision paper SEM-18-030[17] and as further discussed in our response to SEM-18-009 and the Confidential Addendum.

2) Should the minimum MW in each constrained area be adjusted for volumes withheld from the T-4 auction to the T-1 auction for CY2022/23? Which of Options 1, 2 and 3 do you prefer, and why?

We strongly favour Option 1 to procure the full minimum MW requirement in the T-4 auction, particularly in constrained areas, based on the arguments below.

A prudent TSO will be particularly concerned with securing supplies in advance within constrained areas. Withholding demand from the T-4 auction will undermine the TSOs' ability to do so. Furthermore, the price-depressing effect of withholding demand at T-4 provides a signal to encourage exit, which is not desirable within constrained areas, and should be focused within areas with excess supply.

[17] Decision paper SEM-18-030 will result in the de-rated capacity of DSUs reduced in future auctions to reflect their run-hour limitations and also remedied a serious oversight in the first auction which put the long stop date after the end of the period for which new DSUs were contracted to deliver capacity.

To provide the required degree of security in advance, it would be prudent not to withhold any demand at T-4 in constrained areas. The security risks of being left with insufficient capacity in constrained areas is too great as the "pool" of potential resources to make up the gap at T-1, is more limited.

3) Which of the demand curve options, Options A or B, in your view is the most appropriate for the first T-4 capacity auction, and why?

We understand the point made in paragraph 6.4.4 of the Consultation Paper, namely that there is no need to procure the full capacity requirement in a T-4 auction, if the corresponding T-1 auction can make up any shortfall. However, that point may only apply to the system-wide market. As explained above, it applies to a lesser extent, or perhaps not at all, within constrained areas, where the need for planning ahead is more acute.

However, even in the light of paragraph 6.4.4, it is impossible to appraise – or to apply – demand curve Option B, since it is simply not defined. The Consultation Paper shows a sloping line in figure 9, but the position of the sloping line is not defined by reference to any fixed points (unlike the Option A demand curve shown in figures 8 and 9). Adopting Option B as currently stated would give the SEM Committee (or the auction administrators) a free hand in selecting any demand curve. We cannot accept a proposal on that basis.

If the SEM Committee were to offer a choice based on a clearly articulated Option B, we would review our position. However, in the absence of the necessary clarification, we must favour Option A as intrinsically more stable and predictable, because it is tied to known parameters.

Section 7. T-4 Auction Price Caps for 2022/23

1) Do you agree with the proposal to keep the Auction Price Cap (APC) at 1.5 x Net CONE for the T-4 auctions? If not, please explain. Is your response in any way contingent upon the final value of BNE Net CONE for CY2022/23?

At a general level, there is more uncertainty over future costs and infra-marginal rents, when looking four years ahead, than at a T-1 auction. To ensure that Reliability Options remain compatible with future costs of operation, prices need to include a higher margin for error in the T-4 auction than in the T-1 auction. That consideration alone argues for a higher Auction Price Cap in the T-4 auction, meaning a factor higher than 1.5 (given that the Net CONE does not include any such margin). The same reasoning also argues for a higher ECPC.

2) Do you agree with the proposal to keep ECPC at 0.5 x Net CONE for the T-4 auctions? If not, please explain. Is your response in any way contingent upon the final value of BNE Net CONE for CY2022/23?

The ECPC was originally set at 50% Net CONE because the RAs estimated this to be a price above the NGFC of most capacity required to meet the Capacity Requirement. In their analysis, the RAs used Non-Fuel Operating Costs (NFOC) from historical generator financial reporting as a proxy for Fixed Operating Costs in the NGFC formula[18]. However NFOC does not include capital costs associated with

[18] See SEM Committee Decision SEM-18-022.

the operations of the plant. It will therefore be necessary to reset ECPC to include the capital requirements of plants going forward.

At a general level, there is more uncertainty over future costs and infra-marginal rents when looking four years ahead than at a T-1 auction. There is also greater uncertainty over the level of RO difference payments that the holder of an RO will have to make in four years' time. To ensure that Reliability Options remain compatible with future costs of operation, prices need to include specific allowance for higher than expected costs (including RO difference payments) or a higher margin for error in the T-4 auction than in the T-1 auction. That consideration alone argues for a higher ECPC in the T-4 auction, meaning a factor higher than 0.5 of Net CONE (given that the Net CONE does not include any such margin).

Looking to the future, the auction rules prevent the clearing price from rising higher than ECPC unless new entrants enter the market on an unconstrained basis. However, that outcome is perverse. Before new entry occurs, the competitive price in shortage conditions would be higher than the ECPC, and perhaps even higher than Net CONE, so as to encourage new entry. When new entry occurs, the increase in supply would depress prices. The ECPC is therefore holding prices below the competitive level, except in conditions of excess supply, and it should only apply to market segments facing such conditions. In conditions of shortage, before new entry occurs, the ECPC would hold auction clearing prices below the efficient, competitive level. Such a cap would be undesirable and would have to be raised or removed altogether.

3) USPC setting: Do you agree with the proposed approach for UFI submissions?

We have a fundamental concern that the UFI mechanism, whether in a T-1 or T-4 auction, is not fit for purpose in facilitating plant upgrades or refurbishment. As we have repeatedly argued in previous submissions, the current rules will continue to discourage refurbishment and plant upgrades unless they allow *all* significant future investment to benefit from a long-term contract. NERA made this argument clearly in a Memorandum which accompanied our submission to the SEM Committee's consultation on parameters for the next T-1 auction (SEM-18-009):

> *"Most generators applying for a USPC will only be able to bid in a proportion of between ten and twenty per cent of their UFI costs in any given year.*
>
> *These rules present a problem for generators facing UFI costs: being able to include costs within capacity market bids offers no guarantee of recovery of those costs. Generators undertaking UFI but with costs below the New Capacity Investment Rate Threshold (NCIRT) will continue to be eligible for capacity contracts only of a single-year's duration. As a result, a generator may win a contract in the first capacity auction whilst including up to 20 per cent of its UFI costs in its bid; the same generator may fail to win a contract in any subsequent auction at prices that would recover the remaining 80 per cent of its UFI costs.*
>
> *This risk of failing to recover UFI costs is present even for efficient investments that are in end-users' collective interest. It is also commensurately greater for generators constrained on by the system*

> *operator in the capacity market. These generators take risk not only over their relative position in the market-wide merit order but also over whether constraints will endure for the full period necessary to recover their UFI costs. Preventing generators facing UFI costs from recovering them in a single year and excluding them from signing multi-year agreements distorts investment towards new plant able to sign multi-year agreements which are potentially more costly for consumers."*[19]

We cited the NERA Memo in our response to that consultation. However, in the subsequent decisions,[20] the SEM Committee did not refer to these arguments or to our submission or to NERA's Memo when discussing how to set the NCIRT. The current consultation provides an opportunity to remedy this deficiency in regulatory process and to address the concerns raised above about the risks to recovery of UFI. The proposed solution is to introduce a specific category of multi-year Reliability Options with bid limits at APC for plant refurbishment / upgrade, and to have a lower investment threshold for these categories, which we propose needs to be set at €50/kW de-rated capacity. This is discussed further in question (1) in section 9 of the Consultation Paper.

At a general level, there is more uncertainty over future costs and infra-marginal rents when looking four years ahead than at a T-1 auction. To ensure that Reliability Options remain compatible with future costs and revenues of operation, the allowance for estimation uncertainty needs to include a much higher margin for error in the T-4 auction than in the T-1 auction.

Finally, in relation to setting the USPC, we wish to draw to the attention of the SEM Committee certain other problems that are not flagged in the Consultation Paper, but which we have raised at various times.

- First, the concept of Net Going Forward Costs (NGFC) is too narrowly defined. The parameters decision for the T-1 auction stated that fixed costs could be included in NGFC, but it expressly excluded sunk costs, interest on debt and the costs of equity. This approach makes the error of assuming that all interest on debt and the cost of capital in general is a sunk cost. In fact, the cost of continuing operations at a generator includes the cost of financing operations, including access to capital resources, which is an avoidable or forward-looking cost, not a sunk cost. (It can be avoided by not operating the plant.) This is further evidenced and explained in the confidential KPMG report accompanying this response.
- The bidding process for multi-unit generators is too inflexible to cope with the shared costs of operation. The auction needs to include some basis for recognising that forward-looking shared costs (e.g. the cost of managing a power station) persist as long as one unit remains in operation, even if one or more of the other units close down. Hence, if a constrained-on generator submits bids for all the existing units at the USPC, the efficient basis for spreading the forward-looking shared costs among all these units is not known until the auction results are published. If one or more units close down

[19] NERA (2018), Competition and Cost Recovery under the 2019/20 T-1 Capacity Auction Parameters, page 6.
[20] SEM-18-030, Capacity Remuneration Mechanism (CRM) - 2019/20 T-1 Capacity Auction Parameters and Enduring De-rating Methodology: Decision Paper, 01 June 2018

by year 4, because they are not awarded a Reliability Option (or a TCM), some of the forward-looking shared cost will be unrecovered through prices set equal to the USPCs of the other units. That outcome will provide an inefficient incentive for all the successful units to close. The efficient solution is to provide some method of reallocating shared costs, either to the successful units (via contingent bids) or to the units bidding in the following year's auction (by carrying forward the unrecovered shared costs from the previous year). Bidders may choose not to include these carried forward costs in their bids, but there is no reason to deny their recovery if the competitive market allows.

- In relation to constrained on plant operating in conditions of general excess capacity at the system level, limiting the prices paid to NGFC is inefficient, uncompetitive and discriminatory.
  - Plants in the wider system have a chance to capture inframarginal rent in the energy market and in the capacity auction. New entrants may be awarded prices up to and beyond net CONE. However, constrained-on plants bidding their USPC cannot ever receive more than their own NGFC, even if they represent an efficient source of energy and capacity within the constrained area. Any infra-marginal rent is deducted from their USPC. And they are prevented from capturing – and from signalling to potential competitors – the competitive market value of their services, even at times of extreme shortage. These pricing rules do not represent a competitive market outcome, and do not encourage efficient decisions.
  - If the SEM Committee's intention is simply to hold down prices down for existing plant, whilst paying different, higher prices to new entrants, such a policy would be explicitly discriminatory and without objective justification.

In conclusion therefore, provision for UFI through the USPC process, as implemented by the SEM Committee is not fit for purpose. It patently does not facilitate significant investment in plant upgrade or refurbishment and is far too risky for generators constrained on in the capacity market to even contemplate as they are exposed to the unmanageable risk over whether constraints will endure for the full period necessary to recover their UFI costs. An alternative solution is urgently required which we propose above and discuss in more detail later in this response.

The definition of USPC also needs to be widened, and the application of price caps relaxed, to provide efficient economic incentives to existing constrained-on generators.

4) USPC setting: Do you agree with the proposal to apply 2% p.a. inflation projection for estimating costs for CY 2022/23?

In general, we would support a proposal that ties auction parameters to independent external sources, such as BOE and ECB projections. However, in relation to costs, there is significant uncertainty over future values four years in advance, which is not captured by a simple index of inflation. Even using alternative price forecasts (e.g. forward prices for the costs of energy) would not address the problem of risk. Because costs such as TUOS charges, business rates and wages cannot be secured four years in advance of the date on which they are incurred, it will be necessary to make allowance for uncertainty by including an error margin in all calculations of USPCs.

Section 8. De-rating Factors

1) Do you have any views on the proposal of EMDF value of 60% subject to review and update of the analysis for the decision paper?

2) Do you expect to be applying to qualify a new interconnector between the I-SEM and an external market other than GB?

3) Do you have any feedback on the issues around transitioning from the interim to the hybrid solution for cross-border trading of capacity?

As stated in the Consultation Paper:

> *"8.1.22 The new EU Regulation on electricity markets is only a proposal at this stage, and was last revised on 9/11/2017. In its latest form, this requires, as part of article 21, that Regional Security Co-ordinators determine a maximum entry capacity for each interconnector, taking account of its technical availability and the likely concurrence of system stress."*

Assigning capacity to the technical availability of the interconnector is a reasonable reflection of reality. If capacity in Great Britain that wishes to participate in the I-SEM CRM, it must be required to show how it will access the interconnector whenever the TSO requires it for the I-SEM. The proof must take the form of a contract for interconnector capacity (which may be difficult under EU regulations) or else a demonstration that the access rules will allow the TSO to call upon the plant over the interconnector capacity, and that the plant's output will not be diverted into other markets whenever the TSO requires it for the I-SEM.

The total capacity covered by such assurances must not, of course, exceed the de-rated capacity implied by the technical availability of the interconnector(s), requiring a further layer of checks. As we have stated before,[21] a conservative de-rating (low capacity allowance) is required for interconnectors because:

- Their availability is less predictable than for other forms of capacity (being governed by a wider range of factors, including the characteristics of the wider network);
- The predicted direction of interconnector flows during system stress events is highly unpredictable, with the potential for exports adding to demand during such events;
- Interconnector flows into I-SEM represent a relatively high proportion of peak demand (which should also be considered in the context of a system with a high penetration of wind); and
- Great Britain is facing scarcity over the coming years and should therefore be considered a less reliable source of imports, as evidenced for example by increasing exports from SEM to the market in Great Britain over recent months and recent price spikes in GB of £1,000/MWh.

[21] See Energia (2016c), Response by Energia to SEM Committee Consultation Paper SEM-16-051, Capacity Requirement and De-rating Factor Methodology, 5 October 2016, pages 6-9 and 17-19.

If the capacity provider in Great Britain cannot provide the necessary assurances (or loses with ability to do so after the capacity auction but before delivery), the I-SEM will relying on the security of supply provided by the interconnector, but allocating its value arbitrarily to someone in Great Britain who does not actual serve the interests of the I-SEM. As stated in the Consultation Paper:

> *"8.1.23 Article 21 of the latest draft of the EU Regulation, also provides scope for a Member State to prevent capacity from participating in two (or more) capacity mechanisms."*

Capacity cannot be devoted to the GB market and also to the I-SEM. It cannot participate in the I-SEM CRM auction if it has won a contract in the GB capacity auction; it cannot retain an I-SEM Reliability Option if it later wins a contract in the GB capacity auction. The rules of the capacity auction must reflect these features of the real and commercial systems in operation in neighbouring systems.

The purpose of the CRM is to give the TSO some assurance that sufficient capacity will be available to meet demand. That assurance is absent if a generator in Great Britain is allowed to choose between serving the I-SEM or serving the market in Great Britain, particularly if there are stronger financial incentives to sell in Great Britain. It requires a system to ensure that a CMU located in Great Britain is obliged to direct a flow over the interconnector when the I-SEM requires it.

If it proves impossible for capacity in Great Britain to provide the required assurance of access to interconnector capacity, it will still be necessary to limit the amount of capacity procured from Great Britain by the capacity of the interconnector – in terms of *both* de-rated capacity in the auction *and* available capacity at the time of despatch.

In practice, there are strong reasons for assigning capacity to the interconnector, rather than to any putative future users of the interconnector.

The presence of the interconnector provides some security of supply, even if capacity in Great Britain does not obtain a contract for a Reliability Option in the I-SEM's CRM auction. Capacity in Great Britain that does not secure a Reliability Option will nevertheless benefit from the high energy prices (with no need to make a rebate), if it supplies energy to the I-SEM over the interconnector. Failure to offer Reliability Options to generators in the GB market will not therefore rule out the use of capacity located in Great Britain in the I-SEM.

Section 9. New Capacity Investment Rate Threshold (NCIRT)

1) Do you agree with keeping NCIRT at €300/kW, in the light of new evidence on BNE gross investment costs? Does your view depend on the choice of BNE reference plant resulting from the Best New Entrant consultation (SEM-18-025)?

As we have repeatedly argued in previous submissions, the auction rules will continue to discourage refurbishment and plant upgrades unless they allow *all* significant future investment to benefit from a long-term contract. NERA made this argument clearly in a Memorandum which accompanied our submission to the SEM Committee's consultation on parameters for the next T-1 auction (SEM-18-009):

> *"Most generators applying for a USPC will only be able to bid in a proportion of between ten and twenty per cent of their UFI costs in any given year.*
>
> *These rules present a problem for generators facing UFI costs: being able to include costs within capacity market bids offers no guarantee of recovery of those costs. Generators undertaking UFI but with costs below the New Capacity Investment Rate Threshold (NCIRT) will continue to be eligible for capacity contracts only of a single-year's duration. As a result, a generator may win a contract in the first capacity auction whilst including up to 20 per cent of its UFI costs in its bid; the same generator may fail to win a contract in any subsequent auction at prices that would recover the remaining 80 per cent of its UFI costs.*
>
> *This risk of failing to recover UFI costs is present even for efficient investments that are in end-users' collective interest. It is also commensurately greater for generators constrained on by the system operator in the capacity market. These generators take risk not only over their relative position in the market-wide merit order but also over whether constraints will endure for the full period necessary to recover their UFI costs. Preventing generators facing UFI costs from recovering them in a single year and excluding them from signing multi-year agreements distorts investment towards new plant able to sign multi-year agreements which are potentially more costly for consumers."*[22]

We cited the NERA Memo in our response to that consultation. However, in the subsequent decisions,[23] the SEM Committee did not refer to these arguments or to our submission or to NERA's Memo when discussing how to set the NCIRT. The current consultation provides an opportunity to remedy this deficiency in regulatory process and to address the concerns raised above about the risks to recovery of UFI.

In doing so, the RAs will be able to correct a misunderstanding on which the decision was partly based. When deciding not to *lower* the NCIRT for the first T-1 capacity auction, the SEM Committee relied on alleged international precedent:

> *"The New Capacity Investment Rate Threshold (NCIRT) was set in light of experience in other markets together with international benchmarking as set out in the first CRM Parameters decision (SEM-17-022). The SEM Committee has decided to keep the NCIRT at €300,000 per MW. New capacity which does not meet this threshold can participate in the capacity auctions for single-year Reliability Options"*[24]

In fact, international precedent does not support the SEM Committee's position. Agreed, the British capacity market imposes a qualifying capital expenditure threshold of £250/kW to be eligible for 15-year agreements, which is at a similar level to the NCIRT of €300/kW in Ireland. However, the British capacity market also offers 3-year agreements for refurbishments which incur capex of at least £125/kW,[25] a

[22] NERA (2018), Competition and Cost Recovery under the 2019/20 T-1 Capacity Auction Parameters, page 6.
[23] SEM-18-030, Capacity Remuneration Mechanism (CRM) - 2019/20 T-1 Capacity Auction Parameters and Enduring De-rating Methodology: Decision Paper, 01 June 2018
[24] SEM-18-030, para 2.4.2.
[25] EMR Delivery Body (2017), *Capacity Market User Guide*, para 52.

threshold corresponding to less than 20 percent of gross CONE. No such multi-year agreement is available for similar investments within the I-SEM.

Indeed, the current Consultation Paper on the parameters for the T-4 auction now cites a key difference between international mechanisms and the current CRM rules as justification for its decision not to *increase* the NCIRT from current levels:

> *"The SEM Committee now seeks feedback on the evidence presented in this document on gross investment costs, and will make the decision on the NCIRT value in conjunction with the choice of new BNE reference plant. However, the SEM Committee is considering keeping the NCIRT at €300/de-rated kW in nominal terms, given that:*
>
> - *Respondents to the previous CRM Parameters consultation generally supported a lower limit,* ***not least because the I-SEM regime does not have a refurbishment category, for those investors investing an intermediate amount****; and*
> - *The estimates of gross investment costs have not changed substantially."* (emphasis added)[26]

The statement highlighted in bold text acknowledges the key difference in the treatment of refurbishment between the I-SEM and other capacity markets. The treatment of refurbishment in the I-SEM was discussed in a previous consultation and led to a decision to allow the inclusion of Unavoidable Future Investment (UFI) in Unit Specific Price Caps.[27] However, as discussed earlier, the UFI mechanism is not fit for purpose. Indeed, the statement highlighted in bold text suggests that the SEM Committee agrees in principle that the I-SEM should do more to facilitate refurbishment, because the threshold is still too high. Indeed, keeping it at €300 per de-rated kW already implies the RAs are setting it at 31-39 percent of gross CONE (as currently estimated),[28] somewhat below the previous stated level of 40 percent, which provides another indication of a willingness to reduce the impact of the NCIRT. However, this proposal does not remove the inefficient disincentive against refurbishing existing plant.

Within the I-SEM, investments face at least the same risks and difficulties in attracting finance, as substantially larger investments in the larger and more stable British market. Comparable thresholds should therefore be significantly lower in the I-SEM than in the British market, not higher (as at present). To resolve the I-SEM's anomalous treatment of refurbishment, therefore, the SEM Committee should:

- Introduce an additional threshold for refurbishments and plant upgrades of €50 per kW of de-rated capacity.
- Once this threshold is met, bid limits should then be determined by APC automatically in line with the British rules for plant refurbishment[29].

[26] SEM-18-028, paragraph 9.17.
[27] SEM-17-022, paragraph 6.3.45.
[28] SEM 18-028, paragraph 9.1.16.
[29] The British rules allow generators to offer their units as both (a) refurbished at a given price and quantity or (b) unrefurbished at a different price and quantity. Only the refurbished CMU is a price maker automatically. In other words a generator cannot offer to refurbish in order to achieve price maker status and then bid freely without refurbishing. It can, however, keep its options open and submit a separate price for the existing and unrefurbished

The applicability of these rules should not be limited by text in any other I-SEM documents which might rule out their application to refurbishments or upgrade of existing capacity at the current level of MW availability[30].

These simple adjustments would level a playing field which currently slopes significantly towards inefficient investment in new plant.

Section 10. Summary of Parameters

1) Do you have any comments on any of the parameters summarised in Table 6, which are not already covered in your responses to other consultation questions?

The assumptions on demand within constrained areas represent a critically important aspect of the CRM mechanism. However, the basis for allocating demand to constrained regions is not yet clear.

So far, the descriptions of demand forecasting for the transitional auctions have set out, with reasonable clarity, the "least-worst-regrets methodology" for selecting the figure for overall system demand. This method will tend to select a system demand forecast toward the upper end of the range in the Generation Capacity Statement (GCS).

There is not equivalent statement of the basis for allocating demand to constrained regions. Previous descriptions referred to the Ten-Year Transmission Forecast Statement (TYTFS) as the basis for the regional demand allocation. However, it is not clear which data was used for this exercise, e.g. the distribution for 2021/22, or the "current" distribution (July 2016 for TYTFS 2017), or some other case.

In any case, these distributions will generate a Dublin regional demand which is inconsistent with the system demand generated by the least-worst-regrets methodology, as they are based on a "median" scenario, rather than a scenario at the upper end (and the data in the TYTFS was out of date – i.e. it had an earlier data-freeze date than the GCS).

We note that there is a case for selecting a system demand forecast toward the upper end of the forecast range, based on the least-worst-regrets methodology. If that methodology will achieve the right balance of "risk vs cost" for customers at the system level, the same methodology should be adopted when setting demand assumptions in constrained areas. In any case, the higher levels of demand forecast for the system as a whole will only be reached if there is significant demand growth in the Dublin area. (Several EirGrid and RA documents have been clear on this point.) Hence the proportion of the demand allocated to Dublin should reflect that expectation, or else the least-worst-regrets principle is not being maintained. The result would be to allocate a greater proportion of the system demand to Dublin than would be generated from the "standard" distribution in the TYTFS.

The consequences of underestimating demand in a constrained area are, if anything, likely to be more severe than for the system as a whole, as the scope for additional

capacity up to the price taker threshold (or above if it applies separately for a price maker memorandum) if its refurbishment project does not clear in the auction.

[30] The current definition of New Capacity in the CMC refers to the "incremental increase in the capacity of an existing Generator, Generator Unit or Interconnector". There may be other texts that require similar revisions.

or remedial measures is much more limited. The impact of a localised capacity shortfall is likely to be more severe, therefore, and to be spread over a smaller set of customers. The standard used to define the balance of "risk vs cost" should therefore be no less risk averse at the local level than for the system as a whole.