Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism

Locational Issues

Consultation Paper

SEM-16-052

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EXECUTIVE SUMMARY

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

The I-SEM includes a Capacity Remuneration Mechanism (CRM) based around the use of Reliability Options. The detailed design for the I-SEM CRM has to date been developed over the course of three consultations and decisions:

- Decision 1 set out a number of key elements of the I-SEM CRM process and the Reliability Option design, including: the methodology for setting the Capacity Requirement; key elements of the Reliability Option product design such as the Reference Price and the high level Strike Price design; eligibility to participate in the CRM; Supplier Arrangements; and the institutional framework. In addition, Decision 1 sets out the Administrative Scarcity pricing in the I-SEM Balancing Mechanisms in conjunction with the protection afforded to Suppliers by the Reliability Option hedge and socialisation of any shortfall in the hedge.
- Decision 2 set out other key elements of the I-SEM CRM design including: interconnector and cross-border arrangements; more detailed elements of the Reliability Option design; the level of the Administrative Scarcity Price; and transitional arrangements.
- Decision 3 focused primarily on the design of the CRM auction which will award Reliability Options to capacity providers, including the arrangements to mitigate market power in the auction. It also considered further the socialisation arrangements to cover instances when Reliability Option difference payments received from capacity providers are insufficient to provide a complete hedge to Suppliers, and detailed design aspects of the Strike Price.

In addition to this paper, two further consultations are on-going in the context of the CRM work stream, namely: a CRM Parameters consultation (expected September 2016) and a CRM De-rating and Capacity Requirement consultation (published in parallel to this paper).

This paper represents a supplemental consultation following on from the CRM 3 Decision Paper. It addresses issues raised by respondents to the CRM consultations to date which are related to the location of capacity resources, in particular during the transition to the I-SEM.

By way of background, the CRM auction is being developed on the basis of a single zone – consistent with the I-SEM energy markets. In the near term there will likely be more existing de rated capacity on the system than will be secured through the initial CRM auctions and, at least initially, there will be significant constraints on the transmission network. In this context, it is recognised that in practice the system is not indifferent to the location of capacity required to meet security of supply requirements across the island.

Having considered the development of the detailed auction design in recent months, the SEM Committee recognise that particular emphasis is needed to support the transition to the new CRM,

including the management of the location of capacity resources. For example, at least until additional transmission investment is commissioned, there is a possibility that some plant required for localised capacity adequacy reasons might not clear in the CRM auction, and a concern that they may exit before replacement plant comes online in each year of the transition period.

To manage the issue, the SEM Committee are proposing a framework, within the CRM, aimed at ensuring there is sufficient generation adequacy in areas that are considered capacity-constrained. The sections of this paper are summarised as follows:

- **Section 1** provides further background and context to this paper.
- **Section 2** of this paper discusses the level of physical constraints that may impact local capacity issues; the materiality of the risk that some existing generation required for local security of supply may not prevail in an unconstrained single zone CRM auction; linkages to ancillary services; and also provides an outline of the proposed mechanism to deal with local issues in the context of the CRM.

- **Section 3** discusses the Auction Design Framework and follows on from CRM 3 Decision Paper (SEM-16-039). The CRM 3 Decision purposefully left certain element of the auction design framework to be resolved in this supplemental consultation, due to interactions with the locational issues discussed in this paper. Specifically, in relation to the choice of auction format and winner determination; the determination of capacity clearing price; and considerations around constrained-off capacity bidders. This section also considerers how locational capacity deliverability constraints would best be represented within the auction mechanism.

1.1.1 While local capacity issues may be expected to be more pertinent in the short to medium term as there is a need to manage exit and entry of capacity providers during a transitional period of the I-SEM, **Section 4** considers longer term issues in relation to dealing with local capacity constraints. In particular, whether the inclusion of locational capacity delivery constraints in the CRM would occur in T-1 auctions, T-4 auctions, or both.

- In CRM 3 Decision Paper, SEM Committee set out its range of measures to mitigate market power in the CRM auctions. The framework of market power controls was comprehensive, and included an Auction Price Cap; a Price-taker Offer Cap which would apply to all existing generators; and a sloping demand curve, which would also serve to mitigate market power. **Section 5** explores whether this framework as currently designed is sufficient to mitigate any additional issues that arise as a result of local security of supply, or whether additional controls are required.

Responses to the consultation paper should be sent to Karen Shiels (Karen.Shiels@uregni.gov.uk) and Thomas Quinn (tquinn@cer.ie) by 17:00 on Thursday 22nd September 2016. Please note that we intend to publish all responses unless marked confidential.

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1. INTRODUCTION

1.2 BACKGROUND

1.2.1 The I-SEM CRM represents a move from a price-based capacity mechanism to a volume-based mechanism where participants must compete to receive any capacity payment. In the I-SEM CRM, capacity payments (i.e. Reliability Option fees) will be made to capacity providers who succeed in the auctions. Critically, a key difference between the I-SEM CRM and the SEM CPM is that in the I-SEM CRM we will only pay for a required volume of capacity[1]. Winners will receive the auction clearing price[2], and losers will not receive a capacity payment. This will result in the I-SEM CRM having much stronger exit / entry signals than the existing SEM CPM.

1.2.2 The SEM Committee decided (in the CRM 1 Decision Paper - SEM-15-103) that the I-SEM capacity requirement should be determined for the I-SEM as a whole. This implies a single zone for capacity, consistent with the single zone approach for the I-SEM energy markets, and is appropriate to a relatively small market and intended to have simplicity benefits relative to a multiple zone approach or other approaches involving locational pricing in larger US markets. Nevertheless, as part of the CRM 1 decision process it was recognised that, in practice, the system is not indifferent to the location of capacity that is secured. The value of capacity may vary by location, reflecting transmission constraints (or the costs to resolve those constraints), as well as transmission losses.

1.2.3 At the time of CRM 1 decision, it was noted that provision for locational signals exists in the Transmission Loss Adjustment Factors (TLAFs) and/or Generator Transmission Use of System charges (GTUoS). CRM Decision 1 also stated that:

- The second North South Interconnector is expected to resolve thermal transmission constraints before they impact the need for new capacity.
- Should other significant and consistent constraints emerge, they would be considered under the bidding zone review process under the Capacity Allocation and Congestion Management (CACM) Regulation.
- The auction systems should be developed to handle multiple zones, should the need arise in the future for separate capacity zones.

1.2.4 Most CRM 1 respondents supported a single zone auction with some giving their support conditional on the completion of the second North-South interconnector. However, a number of respondents did raise concerns regarding locational capacity needs, arguing that this locational need should be addressed by the capacity auctions, and that this issue is a matter of detailed design. While the single zone decision has been made, a number of responses to the CRM 3 consultation (SEM-16-010) continued to be very concerned that there remains a

[1] Consistent with a capacity demand curve, or curves, which take the target capacity requirement as an input.
[2] Except for those awarded Reliability options "out-of-merit", for lumpiness or locational reasons, who will be paid as bid. Clearing prices in the I-SEM will be derived from the intersection of supply and demand curves for capacity

disconnect between the design of the capacity auction, the physical constraints of the all island system and the locational need for the appropriate capacity on the island.

1.2.5 The revised arrangements under the I-SEM are intended to promote competition and deliver price signals to investors regarding entry and exit of capacity such that capacity adequacy and, ultimately, security of supply is delivered to consumers as efficiently as possible. However, it is likely that in the short to medium term at least, locational constraints will bind.

1.2.6 Having considered the CRM design in detail over recent months, and as part of the development of this CRM 3 Decision paper, the SEM Committee have recognised that mechanisms are required to support this transition, taking locational considerations into account for the efficient management of exit and entry of capacity resources.

1.3 ASSESSMENT CRITERIA

1.3.1 The assessment criteria for the proposal for managing locational CRM issues are the same as those applied to the I-SEM High Level Design and as agreed with the Departments in the Next Steps Decision Paper March 2013.

1.3.2 These assessment criteria are set out below:

- **The Internal Electricity Market:** the market design should efficiently implement the EU Target Model and ensure efficient cross border trade.
- **Security of supply:** the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.
- **Competition**: the trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner.
- **Equity:** the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner.
- **Environmental:** while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.
- **Adaptive**: The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.
- **Stability:** the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.
- **Efficiency:** market design should, in so far as it is practical to do so, result in the most economic overall operation of the power system.

- **Practicality/Cost**: the cost of implementing and participating in the CRM should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.

1.3.3 Fundamental to the SEM Committee's consideration of the proposals are the European Commission State Aid Guidelines, particularly in light of the ongoing EC energy sector inquiry including capacity mechanisms. Furthermore, we are actively engaged with the Departments (DCCAE and DfE) and the European Commission as we develop the capacity market design as ultimately EC approval is required for the CRM auctions to commence.

2. OUTLINE OF ISSUE AND PROPOSED SOLUTION

2.1 INTRODUCTION

2.1.1 With the move to a volume based CRM in the I-SEM, it is unlikely that all existing capacity will be awarded a Reliability Option. The volume of Reliability Options which will be awarded will depend upon the estimated Capacity Requirement (which is an input into the demand curve parameters), other demand curve parameters, and the auction bid prices submitted by market participants. Based on current estimates, it is possible that up to 2,600 MW of existing capacity will not be awarded a Reliability Option. Plant that does not receive any capacity payment may choose to exit the market[3].

2.1.2 This section examines:

- The level of physical capacity-related constraints that are likely to apply on the all island system;
- The materiality of the risk, that some existing generation, which is required for security of supply, at least during the transitional period, might not prevail in an unconstrained single zone CRM auction, and may exit absent specific interventions and new capacity would not enter on a timely basis to meet security of supply requirements;
- Linkages to capacity required and contracting mechanisms for ancillary services; and
- An outline of the proposed mechanism to deal with local issues in the context of the CRM.

2.2 CAPACITY REQUIREMENT AND POTENTIAL EXIT

2.2.1 As illustrated in Table 1, the TSOs' forecasts for the transmission peak demand in 2017 range from about a low scenario of about 6,525 MW to a high scenario of about 6,675MW. In CRM Decision 2, the SEM Committee decided that during the transitional auctions enough capacity should be secured and new capacity does not come online so as to ensure plant needed at the end of the transitional period does not close having not been awarded a contract for the start of the period. For example, for capacity delivery year 2017/18 enough capacity to meet the 2020/21 capacity requirement would be secured. The TSO's current estimate capacity requirement in 2020[4] is around 7,500MW in de-rated MW terms. Based on an assumed average de-rating factor of around 90%, this equates to around 8,200MW of "nameplate" capacity, around 2,600MW less than the EirGrid 2016 Generation Capacity Statement estimate of 2017 installed capacity.

2.2.2 The values set out in Table 1, are indicative, and reflect the approach to de-rating and capacity requirement calculation currently being consulted on separately by the SEM Committee[5].

[3] Although for plant >50MW there is a Grid Code requirement to give the TSOs a minimum of 3 years' notice of planned closure.

[4] TSOs existing forecasts are for calendar years rather than capacity delivery year. For the moment we are using the 2020 calendar year forecast to be indicative of Capacity Delivery Year 2020/21.

[5] see TSO report on De-rating methodology and Capacity Requirement for details of methodology. Also available at https://www.semcommittee.com. These papers have been produced simultaneously. Whilst we have

Table 1: Forecast demand and capacity requirements, 2017-2020 (based on the All-Island Generation Capacity Statement 2016-2025 and on indicative results of the Capacity Requirement and De-rating methodology proposed in the TSO's report)[6]

All values in MW	2017	2018	2019	2020
GCS Low TER Peak Demand Forecast	6,767	6,778	6,793	6,821
GCS Median TER Peak Demand Forecast	6,888	6,938	6,980	7,038
GCS High TER Peak Demand Forecast	6,917	6,977	7,074	7,219
Small-Scale Non-market Adjustment	242	251	263	265
Low Market Peak Demand Forecast	6,525	6,527	6,530	6,556
Median Market Peak Demand Forecast	6,646	6,687	6,717	6,773
High Market Peak Demand Forecast	6,675	6,726	6,811	6,954
Reseve Requirement	444	444	444	444
Low Market Demand + Reserve	6,969	6,971	6,974	7,000
Median Market Demand + Reserve	7,090	7,131	7,161	7,217
High Market Demand + Reserve	7,119	7,170	7,255	7,398
Draft De-rated Capacity Requirement from LWR	7,312	7,321	7,401	7,498
Average Installed Capacity to Meet Capacity Requirement	8,012	8,045	8,112	8,229
GCS Installed Capacity	10,817	10,841	10,623	10,636

Source: TSOs' calculations. TER defined as Total Electricity requirement as per 2016 Generation Capacity Statement

2.2.3 Based on current modelling, the TSOs have made a preliminary estimate that the Capacity Requirement for the CRM in 2020 to be around 7,500MW.

2.2.4 In CRM Decision 3 the SEM Committee made a decision to implement a sloping demand curve. Detail on the precise positioning and slope of the demand curve will be consulted upon as part of the CRM Parameters consultation, expected in September 2016. However, in CRM Consultation 2 we provided examples from other markets where the demand curve slope could result in approximately 15-20% extra capacity being secured in excess of the Capacity Requirement of 7,500MW. Such a demand curve might result in securing of anything between 7,500MW and around 9,000MW of de-rated capacity, depending on the prices bid at auction.

2.2.5 However, for the purposes of illustration, assuming an average de-rating factor of about 90%, the 2020 Capacity Requirement of 7,500M de-rated MW equates about 8,200 MW of "nameplate" capacity. Note that the 8,200MW of "nameplate" capacity treats wind capacity as contributing around 500MW of "nameplate" capacity[7] in line with the wind capacity credit approach used in the current Generation Capacity statement, and is therefore not genuine nameplate capacity for wind.

endeavoured to align the numbers presented, in the event of any discrepancies the number presented in the De-rating and Capacity Requirement consultation paper should be regarded as the latest estimates.

[6] Please note the Small-Scale Non-market Adjustment may not apply post 2019.

[7] Exact capacity credit varies by year, in line with estimates in 2016 Generation Capacity Statement, and is just under 500MW in 2017 and just over 500MW by 2020

2.2.6 By contrast, the 2016 Generation Capacity Statement indicates that in 2017 there is likely to be approximately 10,800 MW of generation, interconnector and DSU capacity on the system in 2017, i.e. approximately 2,600MW of installed capacity more than the estimated 2020 Capacity Requirement.

2.2.7 Whilst clearly the effect of the sloping demand curve will impact upon the amount secured at auction, these broad estimates indicate that there is potential that up to 2,600 MW of "nameplate" capacity may not be awarded a Reliability Option in an unconstrained auction for Capacity Delivery Year 2017/18 (if prices bid are high), and may receive an exit signal.

Other factors affecting exit

2.2.8 We cannot be sure of the extent to which, absent intervention, the capacity providers who lose in the CRM auction would be capacity which is required for local security of supply during the transitional period, and the extent to which this plant will exit as a result of losing in the auction.

2.2.9 However, there are a number of other factors which impact upon whether plant can/will exit, including:

- Grid Code requirements; and
- Other legacy support arrangement

Grid Code impact

2.2.10 The Grid Codes in Northern Ireland and Ireland require generators (greater than 50MW) to give the respective TSOs 3 years' notice of their intention to close capacity[8]. This means that a generator which loses a transitional auction held in 2017 for Capacity Delivery Years 2017/18 or 2018/19 would be prohibited from closing in those years by its Grid Code. Nevertheless it is recognised that whilst the Grid Code requirement may have leverage over a losing generating unit owned by a portfolio generator, the failure to obtain missing money in a CRM auction could lead to insolvency and may leave some plant with insufficient revenues to operate.

2.2.11 Consideration is also being given to the need to align this Grid Code requirement with the T-4 auction. The CRM 3 decision paper (SEM-16-039) provided flexibility around the T-4 auction which must take place at least 3 years 6 months in advance of the capacity delivery year.

2.2.12 The SEM Committee seeks feedback from stakeholders on:

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

[8] For generators below 50MW the requirement is for 2 years notice.

Impact of legacy support arrangements

2.2.13 There are a number of capacity providers who have legacy support arrangements which may influence the way in which they bid in the CRM (e.g. make them effective price-takers) and/or affect whether they exit or not, if they do not obtain a Reliability Option. Legacy support arrangements which may limit exit include:

- Various renewable support regimes, in both Ireland and Northern Ireland;
- Some legacy PSO plant in Ireland[9];
- Some legacy Generating Unit Agreements ("GUAs") in Northern Ireland. The two legacy GUAs relate to two generating units at Ballylumford power station that are owned by AES. They have a combined capacity of 595MW, and the GUAs have an expiry date of 23 September 2018[10] with PPB having a five-year extension option[11].

2.2.14 Some of these support arrangements will allow generators to recover their costs, without capacity payments. However, with the exception of intermittent renewables, they will be required to bid into the CRM auctions. In some schemes, the plant owners will not benefit directly if they are awarded a Reliability Option, since the amount of support money they will receive will fall commensurately. If they see themselves as price-takers, they may bid below their true cost, knowing that their missing money will be recovered via the support mechanism, increasing the probability that other plant receives an exit signal. Conversely, they may choose to bid at the Uniform Price-taker Offer Cap, increasing the probability that other plant required for security of supply will receive a Reliability Option.

2.3 EXTENT OF TRANSMISSION CONSTRAINTS

2.3.1 The TSOs' Operational Constraint Update[12] (July 2016) lists a number of System Constraints, which apply at the current time, including Active System Wide Constraints, Active Northern Ireland Constraints, and Active Ireland Constraints. Many of these constraints relate to the need for local ancillary service provision, in particular voltage support. However, a number of them relate to thermal transmission constraints, i.e. the lack of available transmission capacity that means that a minimum generation/storage/load reduction capacity must be located on

[9] There are three peat fired power stations in Ireland. Edenderry power station owned by Bord na Móna has a gross electrical output of 128 MW, and West Offaly and Lough Ree stations owned by ESB, which have outputs of 150MW and 100MW of electrical output respectively. However, Edenderry no longer receives peat PSO support, but receives 30% biomass support

[10] In 2014, the Utility Regulator consulted on whether to cancel these contracts, and decided not to, estimating that the remaining GUAs are likely to result in reductions in costs for Northern Ireland customers. The Utility Regulator has stated that it will keep under review the value of retaining these contracts for consumers from both a policy and economic perspective.

[11] The PPB buys energy, capacity and ancillary services under these GUAs at prices determined by the contract, and sell them into All-Island market at market prices. The PPB recovers any shortfall in net revenue from Northern Ireland customers via the Northern Ireland PSO. However, if the market revenue exceeds the amounts paid out under the GUAs, the surplus is used to offset other PSO costs incurred by customers in Northern Ireland

[12] http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion2_40_July_2016.pdf

one side of a particular transmission constraint. Some, but not all of these constraints may translate into constraints that should be included in a CRM auction.

2.3.2 The main operational constraints identified by the TSOs that can result in some plants or groups of plants being effectively designated as must-run in the SEM are:

- Between Northern Ireland and Ireland: ensure that the total MW transferred between Ireland and Northern Ireland does not exceed the limitations of the North-South tie line. This is a thermal constraint, but also has implication for the distribution of reserve.
- System Stability (3 large units in NI and 5 in ROI are required)
- North West Generation (Coolkeeragh required for voltage support at certain times)
- Belfast Generation (1 or 2 Kilroot units required for voltage stability)
- Dublin Generation (2 large units on load at all times together with EWIC for load flow control reasons)
- Dublin Generation (requirement to run one of Huntstown 1, Poolbeg A or Poolbeg B at higher demand times for load control reasons). This is also, at least in part a capacity delivery issue;
- Southern Generation (requirement to run up to 3 units at certain times for voltage stability reasons)
- Southern Generation (generation restricted, with maxima on generation run in the Cork area and in the southern region in general, which vary dynamically but do not exceed 1100MW in Cork and 1800MW in the southern region in general)
- 400kV network (at least 1 Moneypoint unit needed at all times to support the 400kV network)

2.3.3 The constraints listed above relate to two general issues:

1. Local capacity deliverability, i.e. the ability to serve local load with a sufficient level of reliability given the thermal transfer limits of the transmission system; and
2. Ancillary services requirements, for example localised voltage support constraints.

2.3.4 In practice it is difficult to categorise a constraint as fully being caused by a deliverability issue, or fully being caused by an ancillary services issue. There can be overlap. However, broadly speaking, from a capacity delivery perspective, it appears that there may be two key constraints[13], which might not be satisfied in the transitional period if there is significant exit of existing capacity. The two areas which might end up with insufficient capacity are:

1. North of the North-South constraint, which exists between Ireland and Northern Ireland; and
2. In the Dublin area.

2.3.5 By implication, there may also be capacity in the rest of Ireland (particularly in the southern region), which is not effectively able to contribute fully towards meeting the security standard,

[13] Note that these constraints have been identified based on the operational limits, which do not represent a planning view of the needs of the system but rather the current operational needs. Note also that these constraints largely represent load flow requirements (but the issue of load flow is somewhat mixed with inertia and voltage as these are difficult to separate without more detailed study).

due to the lack of sufficient capacity to export from these regions to the load pockets in Northern Ireland and in the Dublin area.

2.3.6 In the short term, the most significant deliverability constraint is the North-South constraint (see for instance the 2016 Generation Capability Statement). The existing limited interconnector transfer capacity between North and South effectively limits transfers between Ireland and Northern Ireland, and given demand patterns, imposes minimum capacity adequacy requirements on either side of the constraint. However, the limit may not be considered purely a capacity delivery constraint, it takes into account the rescue/reserve flows that could occur immediately post fault inclusive of operating reserve requirements. It is likely that even when the North-South Interconnector is commissioned, this constraint probably does not completely fall away – albeit the constraint on the level of capacity north of the interconnector is certainly reduced.

2.3.7 There are also capacity constraints in the Dublin area, whereby at least one of Poolbeg A, Poolbeg B and Huntsdown 1, need to be on load when the Ireland system demand is greater than 4000 MW.

2.3.8 The TSOs' published Operational Constraints generally illustrate the following:

- There are a number of plant that are required for both local ancillary service and capacity reasons, which, during the transitional phase is likely to make them "must not exit" if alternative capacity does not enter e.g. DSUs;
- It is not always easy to distinguish between capacity and ancillary service constraints. In conjunction with the TSOs we will need to determine a methodology for identifying which constraints are appropriate for consideration within the CRM;
- It is not always possible to determine that any given plant is "must not exit"- quite often the constraints are specified in terms of needing X from Y units in a given area. This has implications for the specification and evaluation of options in Section 3.2.

2.3.9 It is important to recognise that transmission constraints will evolve as, inter alia, the network develops and demand patterns changes for example through the development of data centres in specific locations across the island. These operational constraints will continue to be a mix of capacity constraints and ancillary service constraints.

2.4 LINKAGE TO ANCILLARY SERVICES

2.4.1 While as set out above, the interaction between capacity and ancillary services constraints can be complex, the proposals in this paper are focused on developing solutions to solve local capacity issues and not necessarily to be viewed as a tool to solve ancillary services issues. This is based on the following rationale:

- The CRM is designed to assure capacity adequacy. The capacity "product" is defined as a physical resource, with availability characteristics, and a financial obligation in the form of the Reliability Option (RO). The product definition does not include localised ancillary services obligations. Otherwise, for one thing, it would not be a standardised product any more, and accordingly it would not be appropriate to use an auction with a common clearing price for what would in effect be different products being bought and sold.
- Transparency is key to the success of the CRM auctions, and localised ancillary services requirements are far less transparent or easily quantified than capacity deliverability constraints. If the CRM were used to address multiple complex ancillary services issues then transparency would be lost.
- Practicality: Inclusion of ancillary services constraints for consideration within the CRM could involve a much larger set of constraints, than if capacity deliverability constraints alone are considered, as discussed later in this paper. The SEM Committee believe that taking locational considerations into account in the CRM could produce reasonable results and be effective if restraint is exercised in setting locational needs. However, if this mechanism was used as a transmission backstop to try to get generation that works in all ways with existing transmission, without any allowance for some possible transmission modifications, it could easily degenerate into a situation where location trumps all other factors.

2.4.2 Accordingly, the SEM Committee believe a number of key principles would be appropriate for any locational capacity framework within the CRM:

1) Any locational constraints taken into account within the CRM mechanism would only be used to represent local capacity deliverability constraints.
2) A locational need would only be included in the CRM mechanism where the need is clear and large.
3) The means by which local capacity deliverability constraints are identified and quantified would be simple and transparent to the maximum extent practicable.

2.4.3 As any locational capacity delivery constraint should only be explicitly included in the CRM mechanism where the need is clear and large, based on the evidence set out in Section 2.2 the SEMC is proposing that at most two capacity delivery constraints, the North-South constraint, and a Dublin area constraint are considered for during transitional auctions. The SEM Committee are of the view that there is less evidence to suggest that there are more than these two capacity delivery constraints which could lead to a local security of supply at the current time. However, the use of three or more capacity delivery constraints within the CRM might not be practicable or efficient, and could undermine the viability of the CRM as an effective market-based mechanism.

2.4.4 In relation to the means by which local capacity deliverability constraints are identified and quantified, one option may be that a distinction between capacity deliverability constraints and other locational constraints could be made through the use of a DC (not AC) load flow analysis. The provision of operating reserve, start-up service, and other ancillary services would not be considered within this DC analysis. The analysis would start by quantifying transfer capabilities of transmission network resources, and by quantifying locational demand

forecasts. The purpose of the analysis would be restricted to identifying any significant "load pockets" within the transmission system and quantifying the nature of the constraint on generating units required to be located within those load pockets so as to meet predefined reliability standards.

2.4.5 The SEM Committee recognises that there may be some plant which is required to support local ancillary service requirements, but not local capacity delivery, which does not receive sufficient revenue to cover its Net Going Forward Costs through a combination of all-island ancillary service tariffs, and Reliability Option Fees. The SEM Committee will separately review the appropriate compensation arrangements for any such plant outside the CRM, and notes that consistent with DS3 System Services Procurement Design Decision paper (SEM-14-108 December 2014), the option remains as a last resort for bi-lateral contracts where specific localised system security requirements can be demonstrated by the relevant TSO. The SEM Committee notes that bi-lateral contracts to support localised ancillary service requirements are a feature of a number of electricity markets, and that the TSOs' licences obligates them to secure necessary ancillary services on an economic basis[14].

2.4.6 Over time there will of course need to be some flexibility to take account of changing circumstances and learning from previous auctions and the SEM Committee will continue to take a holistic view of the issues and the interactions between the various I-SEM workstreams and ancillary services arrangements.

2.5 PROPOSED SOLUTION

2.5.1 The SEM Committee have considered a range of proposals to manage local capacity constraints, such as, addressing them outside or within the I-SEM market and before or after the CRM auctions.

2.5.2 In considering options available, the SEM Committee favour, to the maximum extent possible leveraging the proposed CRM framework and using an "out-of-merit" Reliability Option (with a higher Reliability Option fee) as a mechanism to ensure sufficient capacity is available to deal with specified local capacity delivery constraints. In the longer term (as discussed later in this paper) the SEM Committee also see merit in further developing the relevant transmission locational signals.

2.5.3 In this respect, the TSOs would be required to specify constraints before the CRM auction in a transparent manner to the satisfaction of the SEM Committee. Where the locational capacity delivery constraints were not met in an unconstrained analysis of capacity supply and demand in the auction, the CRM Delivery Body would award pay-as-bid Reliability Options to those out-of-merit capacity providers needed to satisfy the constraint, based on some deterministic rules which seek to identify a least cost solution.

[14] For instance, in Ireland see Condition 11- Economic procurement of Asset, Services and Ancillary Services of the Consolidated Transmission System Operator Licence granted to EirGrid, March 2009

2.5.4 As set out in CRM Decision 3, each existing generator will be required to submit a bid, at or below the Uniform Price-taker Offer Cap, unless it puts in an application for a higher unit specific bid limit on grounds of higher Net Going Forward Costs. Thus the price of the out-of-merit Reliability Option for an existing generator would be no higher than the Uniform Price-taker Offer Cap, unless the generator concerned had successfully made the case to the SEM Committee that its costs exceed the Uniform Price-taker Offer Cap.

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

2.6 SUMMARY OF QUESTIONS

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

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

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

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

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

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

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

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

3. AUCTION DESIGN FRAMEWORK

3.1 INTRODUCTION

3.1.1 The CRM 3 Decision Paper purposefully left certain key element of the Auction Design Framework to be resolved in this supplemental consultation, due to interactions with the locational issues which are raised here. Specifically:

- **Auction format and winner determination**. The CRM 3 Decision Paper narrowed the options for the auction format down to CRM 3 Auction Format Option 1 (simple sealed bid) or CRM 3 Auction Format Option 3 (sealed bid combinatorial). CRM Decision 3, set out an approach for dealing with the lumpiness issue (inflexibility constraint), which was predominantly a simple sealed bid format, but had elements of a combinatorial auction at the margin. CRM Decision 3 noted that there are strong similarities in handling any locational constraints and the inflexibility/lumpiness constraint, and that the auction format option chosen should take both constraints into account. The impact of locational and inflexibility/lumpiness constraints is discussed in Section 3.2.
- **Capacity clearing price determination**. The CRM 3 Decision Paper also left open a final element regarding the method of capacity price determination, namely whether the capacity price should be set by the highest unconstrained bid in merit or alternatively by the highest winning bid in the unconstrained merit order (as illustrated by Figure 2 in this section). The difference between the highest unconstrained bid, and the highest winning bid in the merit order can be more material if multiple bids are "constrained-off" for locational reasons. This question is addressed in Section 3.3.
- **Constrained-off payments**. There remains open a question as to the treatment of any bidders that would have been accepted in an unconstrained auction, but which are not awarded a Reliability Option because of constraints (whether locational or inflexible, or a combination) and whether they should be compensated for being "constrained-off". In the CRM 3 Decision paper, the SEM Committee did not envisage making payments to capacity providers constrained-off for inflexibility reasons. The SEM Committee does not favour compensating capacity constrained-off for locational reasons either, but the pros and cons of compensating constrained-off capacity providers is discussed in Section 3.4, and we seek feedback on this point.

3.1.2 There are also a question regarding how locational capacity deliverability constraints should best be represented within the auction mechanism. This point is addressed in Section 3.5.

3.2 AUCTION FORMAT AND WINNER DETERMINATION

3.2.1 In CRM Consultation 3 we explained how a simple sealed bid auction would work (CRM 3 Auction Format Option 1). In the absence of constraints, a simple sealed bid would be the preferred option. It is simple, easy to implement, less amenable to the exercise of market power[15] and more transparent than other options considered. A simple sealed bid auction

[15] CRM Decision 3 rejected the descending clock option, as it is more amenable to exercise of market power.

would rank bids in price order, and accept all bids whose price is less than the price at which the supply curve cuts the demand curve. These bids would be deemed winners and awarded a Reliability Option for the full MWs of its bid. The marginal bid would be awarded a Reliability Option on that part of its bid which was below the point where the supply and demand curves intersect. (The marginal bid segment is the one whose position on the supply curve is where the supply curve intersects with the demand curve).

3.2.2 In CRM Consultation 3, we introduced the concept of a limited combinatorial auction to solve the lumpiness problem (i.e. an inflexibility constraint). In CRM Decision 3 we stated that a bidder would be allowed to submit an inflexible bid segment, which would constrain the CRM Delivery Body to accept all or nothing of that bid segment. However, the CRM Delivery Body would be required to calculate if there are some combination of out-of-merit bids (i.e. bids which are higher priced than the marginal bid[16]), which deliver greater social welfare[17] than the marginal bid, and to accept the combination that delivered the highest social welfare. A higher priced bid might deliver higher social welfare if it is a better "fit" to the residual capacity requirement than the marginal unit.

3.2.3 CRM Decision 3 limited the extent to which combinatorial solutions could be applied to solve the inflexibility constraint. This prevented rejecting an in-merit bid (not including the marginal unit) in favour of the marginal unit, or out-of-merit units on grounds of lumpiness/ inflexibility. It did so, because otherwise smaller units are more likely to be rejected if there is a large inflexible unit on the margin[18], and rejecting a smaller, cheaper unit would be inequitable. However, the SEM Committee did not preclude the possibility that bids which are in-merit on an unconstrained all-island basis would be rejected on grounds of locational constraints.

3.2.4 When locational constraints exist, it raises some further key questions. For example: Where a capacity provider A, which is on the under-supplied side of the transmission constraint is required to satisfy a constraint (i.e. "constrained-on", but is more expensive than another capacity provider, B, which is in-merit in a non-transmission constrained schedule) should A be awarded a Reliability Option in addition to B, or *instead* of B (i.e. should B be "constrained-off"?).

3.2.5 Against this background, a number of options exist for determining the auction winners, simultaneously taking both the lumpiness issue and locational capacity delivery constraints into account. In this supplemental consultation paper we build on the analysis/decisions set out in CRM 3 Decision Paper and set out this list of options (which are variants of the CRM 3 Auction Format Options 1 and 3). The options differ in the solution technique they apply, and potentially in the way that locational constraints are defined.

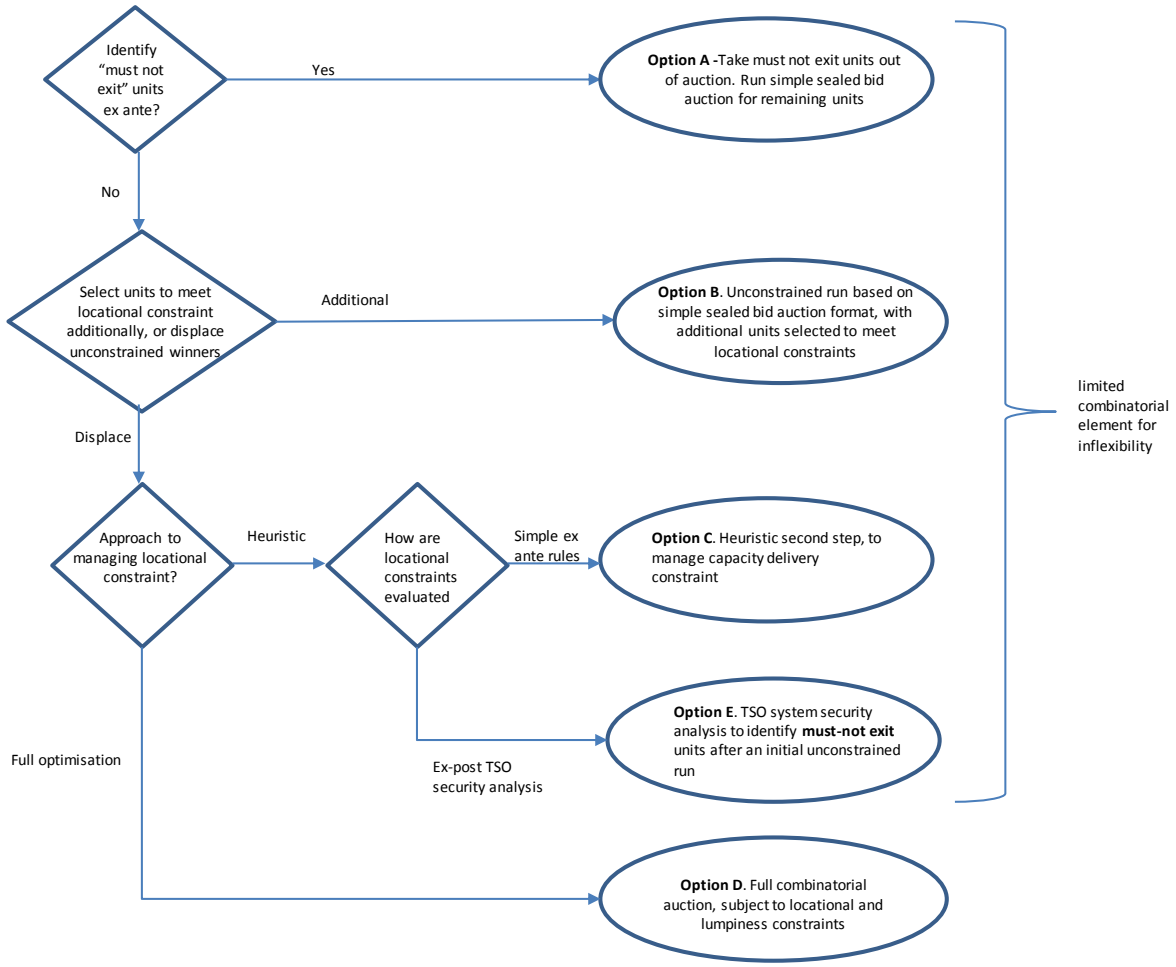
3.2.6 The options are listed here and are described in the following paragraphs:

[16] Or have the same price, but ranked lower on tie-break criteria.
[17] Social welfare is the sum of consumer and producer surplus.
[18] For instance, suppose that the supply and demand curves intersect at 7,000MW. The marginal unit it a large inflexible unit of 400MW, that take the supply curve from 6,800MW to 7,200MW. If there a 10MW unit priced lower than the 400MW unit, then social welfare may be optimised by not accepting the 10MW unit, so awarding 190MW of RO in excess of demand, instead of 200MW in excess of demand

- **Option A: Ex-ante identification of "must not exit" units**. These units would be taken out of the market and treated separately before the CRM auction is run. Their capacity contribution would be netted from the capacity requirement, and the residual requirements secured using a simple sealed bid option;
- **Option B**: CRM Auction Format Option 1 (simple sealed bid) with capacity secured to meet constraints being additional, as described above;
- **Option C:** Simple sealed bid, but with a "heuristic-based" second step which applies some rules to reduce capacity secured in surplus capacity regions to offset additional capacity secured to meet locational constraints, while at the same time addressing the lumpiness issue;
- **Option D:** CRM 3 Auction Format Option 3 (i.e. combinatorial). This option would find the optimal combination of bids to accept, subject to the locational capacity delivery and bid inflexibility constraints; and
- **Option E:** TSO system security analysis to identify must-not exit units after an initial unconstrained run.

3.2.7 Option A would need to include the addition of a limited combinatorial element to assess the relative social welfare outcomes of choosing whether or not to accept the marginal unit and whether to accept any out-of-merit unit combinations, where the marginal unit was inflexible. Options B, C and E would also, with the added complication that there would be multiple marginal units if there were more than one binding locational constraint. Option D employs a full optimisation process to solve the combinatorial problem. These options are depicted in the flow diagram in Figure 1.

Figure 1: Auction format options for managing constraints



Option A (ex-ante identification of "must-not exit" units) Description

3.2.8 Option A is a non-market approach in which specific units that are known or expected to be required in order to solve locational capacity delivery constraints are contracted under mutually-acceptable terms *outside* of the CRM auction and before it takes place. Once they are contracted they are effectively netted out of the capacity auction- i.e. the Capacity Requirement is reduced commensurately, and the demand curve is shifted to the left. They are selected on the basis that when the auction winners are subsequently identified, the total set of capacity providers (must-not exit units and auction winners) should not give rise to locational constraints. The locational issue is dealt with outside the auction, and it would be possible to use a simple sealed bid auction to solve the single zone optimisation as originally envisaged.

3.2.9 There is precedent for ex-ante Reliability Must-Run (RMR) solutions in a number of international markets including North America in particular. Any such RMR units could be awarded a Reliability Option with the option fee set at its regulatory-determined Net Going Forward costs, which by definition, should be sufficient to incentivise it to keep operating. Such a contract would use the same form as the RO being developed for the CRM but the

option fee would be set to the RMR Net Going Forward costs, instead of to the market-clearing capacity price.[19]

3.2.10 It should be noted that it could be commercially advantageous to be designated as an RMR unit if the unit would otherwise not recover its costs. Alternatively it could be a commercial *disadvantage* if the unit would lose the ability to receive market revenues in excess of its costs. Whether it was an advantage or disadvantage would depend in part on the cost structure of the unit concerned. In any event, the designation would be commercially significant and would be an administrative decision as opposed to a market outcome.

3.2.11 A particular disadvantage with this approach is that it might distort long term investment signals, especially for any constraints that are expected to be solved in the short to medium term. This approach might also displace units which would have been successful in the unconstrained merit order and which might have met the locational requirement without an intervention, and the issue of how to account for potential new investment such as DSUs.

Option B (additional capacity)

3.2.12 In principle, it would be possible to apply a simple sealed bid approach to all bids (i.e. CRM 3 Auction Format Option 1), and award Reliability Options to all bids that are in-merit in the all-island unconstrained run, and any constraint infeasibilities that result could be solved by accepting *additional* bids (i.e. none are removed).

3.2.13 There are disadvantages to such approach on the basis that it could lead to inefficiently securing too much capacity, to the detriment of consumers. The extent of additional capacity would be a function of the number of binding locational constraints, and how many MW of bids which are in merit in the unconstrained auction are not deliverable because of locational constraints. There would be a potential inconsistency with the principle of maximising social welfare set out in CRM Decision 3 and this option. By definition, additional capacity could be purchased at prices that exceeded willingness to pay, and at levels above that necessary to solve the physical constraints.[20]

3.2.14 There are also advantages with this approach in that it would be simple to implement and might have a less distortive impact on long term investment signals, in particular for constraints that are expected to be removed in the short to medium term. For example, this approach would not displace from the unconstrained merit order any winning capacity that might be expected to be competitive in future auctions if or when the constraint has been removed e.g. via a new transmission investment.

[19] As set out in the CRM 3 Decision Paper, any generator may apply to have its Price-taker offer Cap set at a higher level than the Uniform Price-taker Offer Cap, if it can prove that its Net Going Forward Costs exceed the Uniform Price-taker Offer Cap. Hence there will be a regulated process for establishing Net Going Forward Costs, regardless of whether there are any transmission constraint issues. It may be possible to apply the same regulated process for establishing Net Going Forward Costs, to be applied to RMR units as well. The Net Going Forward Costs would be net of any infra-marginal rent that the generator earned, including from location specific ancillary service payments.

[20] If this approach was implemented and extra capacity is secured due to binding locational constraints, it might be possible that participants reflect the potential reduced possibility of scarcity in their bids in subsequent auctions, therefore reducing the RO auction clearing price signal.

3.2.15 Another advantage to Option B is that it is transparent. Any additional capacity secured due to binding locational constraints can be clearly quantified and the mechanism of Option B would be a simple mechanical procedure rather than a heuristic or optimisation.

3.2.16 However, it is anticipated that this approach to handling locational constraints could, at least in the short term, have a potentially significant impact on consumer bills and social welfare. Also, the TSOs may not have any incentive to keep additional capacity to a minimum.

Option C (heuristic approach)

3.2.17 Option C uses a two-step approach. It is based on CRM Auction Format Option 1 (simple sealed bid), but has an additional "heuristic" step to satisfy the locational and inflexibility constraints.

3.2.18 Option C involves two steps:

- **Step 1**: This would be an initial "unconstrained" run of the auction to determine preliminary winners based on a simple evaluation of the supply curve and demand curve, assuming no bid inflexibility and assuming no locational constraints;
- **Step 2**: The second run would adjust the results of the first run, if necessary, to satisfy the locational and inflexibility constraints, using heuristic rules.[21]

3.2.19 A *heuristic* would be developed to find the "best" solution in Step 2, i.e. the one that delivers the highest social welfare. The complexity of Option C would depend on the complexity of the heuristic rule(s) used to solve the locational constraint. At its simplest, it could involve some form of:

- Establishing capacity areas;
- Ranking the "short" capacity constrained areas on the basis of how short the capacity in that area is compared to the minimum required MW level;
- Accepting each "out-of-merit" bid in that under-supplied area in order of cost until the minimum requirement is obtained;
- Moving on to the next "shortest" area and doing the same, until there are no more "short" areas;
- Progressively rejecting bids in "long" areas which are marginal or infra-marginal in the unconstrained run in price order, provided that removing them does not infringe any locational constraints, until no more bids can be rejected without aggregate supply being less than in Step 1.
- The lumpiness issue would be addressed at the same time as addressing the locational issue by ensuring that whenever an inflexible bid was newly accepted or rejected in each stage of the process above, it would be accepted or rejected in *whole*. The process would include consideration of whether or not to accept "new" marginal bids – and if not, whether to accept any out-of-merit bids instead – again, based upon a social welfare criterion.

[21] This second run would simultaneously take into the account, expressed in the CRM 3 Decision Paper, that the winner determination process will require and ensure that all lower-priced segments of a bid from a CMU must be accepted in whole before any higher-priced segment from that CMU is accepted in whole or in part.

3.2.20 Option C would not necessarily find the overall optimal solution, since it does not necessarily consider all combinations of options to solve the locational constraint.

3.2.21 An advantage to this approach is that it is relatively transparent (depending on the complexity of the heuristic). In any event, any out of merit capacity secured and in merit capacity removed due to binding locational constraints can be clearly seen by reference to the unconstrained solution from Step 1.

Option D (combinatorial approach)

3.2.22 Option D here is based on CRM Auction Format Option 3 (sealed bid combinatorial). In this option there would only be one run (unless an initial run is needed to find an unconstrained clearing price), and it would use an MIP solver to find the overall optimal solution[22]. Essentially, the auctioneer would choose the optimum combination of bids to meet the capacity requirement, subject to the applicable locational and inflexibility constraints. The optimum would be that which has the highest level of social welfare.

3.2.23 The transparency of this option would be similar to that of Option C. While an optimisation process might be more independently replicable than the outcome of a heuristic, a key point is that, like Option C, any out of merit capacity secured and in merit capacity removed due to binding locational constraints can be clearly seen by reference to the unconstrained solution. The unconstrained solution remains transparent in the case of Option D, even though it is not part of the solution methodology, since it is the basis of the clearing price determination (refer to Section 3.3).

Option E (ex-post TSO system security analysis to identify must-not exit units)

3.2.24 Option E is a two-step process like Option C:

- **Step 1**: Exactly the same as in Option C, there would be an initial "unconstrained" run of the auction to determine preliminary winners based on a simple evaluation of the supply curve and demand curve, assuming no bid inflexibility and assuming no locational constraints.
- **Step 2**: In this step the TSOs would take the results of Step 1 and perform a system security analysis based on the assumption that only the capacity of infra-marginal winning bids remained in physical operation. To the extent that any additional units were identified as being required by the system they would be designated as "must-not exit", like in Option A – i.e. deemed to be winning bids also – and paid as bid.

3.2.25 Option E has the attraction at face value that it only introduces complexity (i.e. Step 2) to the extent there is actually a locational problem to solve. It also has the considerable advantage that it is the option that performs best on the criterion of ensuring system security. Essentially, the TSOs can take whatever actions are necessary to ensure security of supply. In particular, under Option E, the TSOs have the ability to check for constraints that might not

[22] An "MIP solver" is a specialist software module that can be given a set of yes/no decisions to make for specified decision variables, a set of constraints to be observed, and an objective function to maximise. It will then determine the optimal solution – i.e. which decision variables should be set to "yes" and which should be set to "no", so that the overall objective is maximised subject to the constraints.

have been anticipated before the auction was run. For example, a large number of new plant or DSUs might bid to build in a location that is currently unconstrained, but if they were all accepted in the auction would cause new constraints. If the TSOs could analyse this situation after bids have been submitted but before they have been awarded then potentially any new and unanticipated infeasibilities could be avoided.

3.2.26 Option E may have some significant disadvantages however:

- **Too big of a failsafe?** Step 2 of Option E is essentially a failsafe mechanism that allows the TSO to take over from the market when the TSOs deem the market to have produced an unacceptable solution. However the RAs are concerned that any failsafe mechanism should not be relied upon as a matter of course. In the event Option E is not selected some form of failsafe will exist in any event – meaning that security of supply will still be ensured. The difference is that if Option E is not selected the failsafe should only be enacted very rarely.
- **Doesn't solve the best mix problem**: To the extent that Step 2 of Option E secures additional capacity, there will exist the same problem that Option C set out to solve: what is the best mix of changes relative to the unconstrained solution (i.e. to potentially reject some bids and possibly even accept some others) so as to accommodate the additional units and not secure too much capacity for the system in total.
- **Potential for lack of transparency**: A concern with Option E is that the system security analysis could yield results with commercial significance for market participants, yet the analysis is likely to be somewhat opaque. The analysis will rely on a complex set of models, for which parameter changes or methodological tweaks could result in different answers. Market participants would only be able to observe the consequences after the auction was run and the analysis performed. There may be concern that the TSOs were being unduly conservative or including ancillary services or other considerations as part of their criteria. By way of contrast, if Options B, C, and D use locational capacity deliverability constraints as inputs to the auction process, those constraints are quantified as specific numbers and can be more easily understood – as can the use of those constraints in the auction mechanism itself.[23] It would be ideal from a transparency perspective under Option E if the system security analysis could be simplified to the point where the system requirement was represented as a small number of locational capacity deliverability constraints which were developed and made clear to market participants ex ante. However, if that were the case then Option E would essentially be the same as Option C – with only the details of the heuristic methodology to be decided.

Evaluation of Options

3.2.27 The options differ in a number of key evaluation criteria, namely:

- **Internal market**. Some options may have a higher risk in terms of compliance with the State Aid Guidelines.
- **Competition**:

[23] It is also possible that the development of these constraints, using DC load flow models or other approaches, would also be more transparent than an ex-post system security analysis.

- Some options take some bidders out of the market and potentially reduce competition
- Other options may deliver less transparent and stable results

- **Efficiency**. For example, will the solution deliver the optimum solution, i.e. one which delivers the maximum social welfare?
- **Practicality and cost**: there are some potentially significant differences in the complexity and deliverability of the IT solutions, and some solutions may not be deliverable for the first transitional auction(s), but could be feasible for subsequent auctions. Key questions include:

    - Can the IT solution be built in time for the first auction?
    - What is the risk that the algorithms are not solvable in a reasonably finite time

3.2.28 A summary evaluation of the key pros and cons of these options against the relevant criteria is set out in Table 2 below.

Table 2: Preliminary evaluation of auction design options

	Pros	Cons
Option A: Ex-ante identified of "must not exit" units taken out of market, then simple sealed bid	**Practicality**: Easier IT solution to implement- lower risk that cannot be implemented in time for first auction. **Practicality:** Lower risk that algorithms cannot be solved in finite time (although still has combinatorial element at margin)	**Internal market and competition**: takes units out of the market ex-ante, so reduces competition, and may be State Aid complications with units taken out of the market **Competition and transparency**: lacks transparency on units taken out of the market. May exclude some units from being considered as a solution. **Efficiency**: may not deliver optimum solution by taking bidders out of the market **Practicality**: Difficulty in identifying units in advance of the auction.
Option B: Simple sealed bid, with capacity secured to meet constraints being additional	**Practicality**: Easier IT solution to implement- lower risk that cannot be implemented in time for first auction. **Practicality:** Lower risk that algorithms cannot be solved in finite time (although still has combinatorial element at margin). **Security of Supply:** Rates high on system security of supply as additional capacity procured. **Efficiency**: May be longer term efficiency benefits if constraints are resolved in the short term	**Efficiency**: risk that may not deliver optimum solution by procuring more capacity than required, to detriment of consumer bills **Competition:** less competitive pressure on capacity providers in over-supplied region
Option C: Simple sealed bid, but with a "heuristic-based" second step, to reduce capacity surplus in	**Practicality:** While the heuristics remain to be designed, it is expected that this option can be implemented in time for the first auction	**Efficiency:** May not deliver optimum solution, unlike Option D.

surplus regions	**Efficiency:** Likely to deliver more efficient solution than Options A and B	
Option D: combinatorial optimisation	**Competition: L**ikely to deliver competitive outcome **Efficiency:** Likely to deliver most efficient solution	**Practicality**: May not be possible to implement this IT solution in time for first auction. **Practicality**: Risks around how long solution takes to solve, particularly with significant numbers of new entrants? **Competition and transparency**: Results from combinatorial auctions may lack transparency
Option E: ex-post TSO system security analysis	**Practicality:** Low implementation risk **Efficiency:** Efficiency may be increased as locational constraints may change if new entry clears in the auction. **Security of Supply:** Rates high on system security of supply due to ex-post assessment capturing potentially new constraints following auction outcome.	**Competition:** There is potential for a major transparency issue. To the extent this is addressed however, this approach would tend to resemble Option C **Practicality**: Does not solve the issues addressed by Option C. **Internal market and competition**: takes units out of the market ex-post, so reduces competition, and may be State Aid complications with units taken out of the market

Internal market

3.2.29 Option A entails taking some units out of the market ex ante, and awarding them Reliability Option contracts outside the auction. Whilst clear and objective criteria would be put in place for determining which units would be taken out of the market, further discussion would be required with the EC to determine whether such an approach would receive State aid approval - given the lack of a full competitive process. Option E faces a similar issue, the key difference being that the timing is ex post, not ex ante.

3.2.30 In all cases the additional costs of out of merit capacity would be added to capacity costs recovered through supplier charges.

3.2.31 Option B could result in more capacity being required in some over-supplied areas than is necessary to support system security, which could also complicate the State aid approval process.

3.2.32 Options C and D could be more compatible with the State aid guidelines.

Competition

3.2.33 Option A results in materially reduced competition, by taking some bidders out of the market ex ante. One of the key drawbacks of Option A involves the practicalities associated with determining which units to designate as "must not exit". For example, if three units are needed in a region that has five, it is not clear at all which of these units – if any – should be designated as such. As mentioned above, the commercial importance of being designated as "must not exit" could be significant – either in a positive way or a negative way. One principle to start with might be to choose the three cheapest units but, this would imply that the units concerned have already made bids to the auction. This being the case, the ex-ante aspect of Option A would not really apply, and the methodology would again start to be more akin to Options B, C, and D.

3.2.34 Option B would not serve to intensify competition as much amongst bidders in any over-supplied areas, since there is no risk that they will be "constrained-off" unlike in Options C and D.

3.2.35 However, arguably over the longer term Option B may help retain capacity that may otherwise face an exit signal but would be expected to be competitive, if and when the constraint is resolved, hence potentially improving longer term economic signals.

3.2.36 As discussed above, in a combinatorial auction (Option D), it is not always transparent why a bid has not been selected- e.g. in the case of this auction, whether for locational or inflexibility reasons.

3.2.37 Option E performs very poorly on the competition criterion because of the potential lack of transparency associated with the system security analysis.

Efficiency

3.2.38 Options A, B and E are likely to deliver significantly less efficient solutions than C or D (at least in the short term as measured by the duration of the RO contracts awarded), where material

constraints bind. Lower efficiency is partly as a result of reduced competition, particularly in Option A. Lower efficiency is also the result of simply not necessarily picking the lowest cost set of capacity bids in order to meet the system's capacity need. In the case of Option B there is the risk in particular that more capacity will be awarded Reliability Options than is required to meet the system's capacity adequacy requirements, which could have a significant impact on consumer bills.

3.2.39 The use of Option D was initially considered in the CRM 3 consultative process to be unnecessarily complex, in the absence of significant constraints. Further, the SEM Committee rejected an option which would allow fully in-merit bids to be rejected for lumpiness reasons alone (using a fully combinatorial approach). However, in the context of simultaneously managing both lumpiness and locational constraints, the balance of costs and benefits may change. Option D could deliver significant efficiency advantages in the presence of material locational capacity delivery constraints, over Option C- which is not guaranteed to deliver the optimum solution, even within the constraints specified.

3.2.40 In this context it should be taken into account that when a solution methodology (either heuristic or optimisation) simultaneously takes multiple constraints into account, it is not usually possible to attribute with certainty that a particular constraint is the reason why a particular bid was or wasn't selected. It is usually a combination of interacting factors, and here the interaction between lumpiness and locational constraints is the key consideration. It means that it may not be feasible to have an approach under Option D (and possibly Option C) in which fully in-merit bids could be retained on the basis that otherwise they would have been rejected for lumpiness reasons *alone*.

3.2.41 Achieving the most cost-efficient outcome while at the same time adhering to all relevant constraints may require deviating from a simple unconstrained merit order solution. The RAs recognise the responses to the CRM 3 Decision Paper in which a majority of respondents disagreed with the proposed principle of accepting "out of merit" bids to lower costs as part of managing lumpiness. In general, most respondents preferred lumpiness to be managed by accepting the marginal bid with consumers meanwhile benefiting from a higher standard of security of supply. One respondent considered that keeping the marginal bid in all circumstances was the only option consistent with SEM CRM 1 decision regarding 8 hour LOLE.[24] Other concerns were that the price would be depressed by the rejection of marginal

[24] Alternatives suggested included partial acceptance of offers, allowing divisible bids, flexing the capacity requirement to ensure all or nothing acceptance or accepting the marginal bid within a tolerance band and manage discrepancies in T-1 auction. All of these suggestions are in the context of lumpiness alone. The suggestion of providing for partial acceptance of offers and allowing divisible bids has been accepted and accommodated with the provision of an option to submit flexible bids. Flexing the capacity requirement to ensure all or nothing acceptance (if required) has been accepted in the form of the sloping demand curve, which by definition establishes a tolerance band and a range of prices over which bids are evaluated within that band. Finally, managing discrepancies within the T-1 auctions is an inherently sensible suggestion as well, in the context of managing lumpiness, but might not be extendable to the issue of locational capacity delivery constraints – if for example there could be units selected in the wrong locations in the initial auction, or if there were multiple marginal units because of binding constraints.

bids.[25] The RAs are concerned however that with the consideration of locational constraints in addition to the lumpiness issue, the inefficiency associated with not optimising may be high. In CRM 3, many respondents tended to prefer options for managing lumpiness that would have resulted in higher prices to consumers. All options ultimately pass capacity prices through to consumers as a non-by passable charge. For the protection of consumers, the RAs place great importance on market efficiency and delivering efficient prices. For this reason the RAs are concerned about the risk of any methodology systematically procuring more capacity than is needed,[26] or procuring the needed capacity at an unnecessarily high cost by selecting something other than the most efficient set of bids.

Practicality and cost

3.2.42 There are two key practicality risks. Can the solution be built in time for the first auction? And will the auction software be able to solve the problem in a reasonably finite time period.

3.2.43 Firstly, there is the risk that the IT solution cannot be delivered and tested appropriately in time for the first transitional auction. Option A involves a relatively straightforward IT solution, a simple merit order approach with a limited combinatorial solver, to solve the marginal lumpiness problem. Option B involves the additional complication of the potential for multiple marginal units. Option C involves the same requirements as Option B, but with the addition of an additional heuristic mechanism- with details (and hence complexity) of that mechanism to be specified.

3.2.44 Option D would not require heuristic mechanisms to be developed at all, but would both require the use of a Mixed Integer Programming (MIP) solver, to identify the optimum combination of bids to accept.

3.2.45 The TSOs (in their capacity as the CRM Delivery Body) have advised us that it is likely that it will be possible for them to implement an IT solution to support Option C in time for the first transitional auction, but it is unlikely that they will be able to implement the IT solution to support Option D in time for the first transitional auction. If used at all, Option D could therefore only be part of an enduring solution where a different option (i.e. Option A, B, C or E) was used on a transitional basis.

3.2.46 The second key aspect of practicality is how long the IT solution takes to solve. In an optimisation process, the solution time can grow exponentially as the size of the problem increases. Evaluating a problem in a reasonable amount of time might prove challenging.

3.2.47 Large numbers of bid combinations can be ruled out as clearly inferior to others, without needing to calculate them, but nevertheless there remains a risk, that in the absence of a heuristic rules, which provide short cuts (but will not necessarily deliver the optimum solution)

[25] The point regarding a depressed capacity price from rejecting marginal bids is important and is discussed in Section 3.3.

[26] The RAs believe the best tool for expressing the trade-off between capacity adequacy and cost is the capacity demand curve, this is its explicit purpose, and the action winner-determination process should explicitly take it into account. The winner determination process should not arbitrarily and systematically secure too much capacity just because consumers would benefit from a higher standard of security of supply if it did.

an optimisation solver might not be guaranteed to find the optimum solution within the required amount of time.[27]

3.2.48 However, while the risk cannot be ruled out, as a practical matter there is considerable evidence from US markets that an optimisation process can be used to clear capacity markets of a larger size and dimension in acceptable time frames.

Summary preliminary view

3.2.49 Our preliminary view is that:

- Options A, B and E have quite material drawback in terms of competition, efficiency, compliance with State aid guidelines and ultimately in terms of the impact on consumer bills, but options E and B rate higher on Security of Supply. Option E has advantages relating to taking account of changing constraints if new entrants enter the market
- Option D may have advantages as an enduring solution for the method of auction winner determination, albeit it could not be implemented in time for the commencement of I-SEM operations due to TSO constraints; and
- So Option C might be a logical interim solution.

3.2.50 Nevertheless, the SEM Committee welcome alternative views and analysis of the relative advantages and disadvantages of all options.

3.3 CLEARING PRICE DETERMINATION

3.3.1 In the CRM 3 Decision Paper, the SEM Committee decided that the CRM auction would be:

- Pay-as-clear for winning bid segments whose bid price is in-merit, i.e. less than or equal to the market-clearing capacity price; and
- Pay-as-bid for any bids accepted out-of-merit, either for lumpiness reasons or for locational issues in the context of transitional transmission constraints

3.3.2 The CRM 3 Consultation paper considered a number of options as to how to set the clearing price. It rejected one option (highest rejected bid), but deferred the final decision between two remaining options to this supplemental consultation.

3.3.3 The two remaining options under consideration are:

- **Option 1:** The highest-priced bid accepted in the unconstrained merit order.
- **Option 2:** The highest-priced bid which is both: (a) accepted in the unconstrained merit order; and (b) selected as a *winning bid* after lumpiness and locational considerations have been resolved.

3.3.4 The difference between the two options can be illustrated with respect to the following worked example, where some generators in Region 1, which are in-merit in an unconstrained

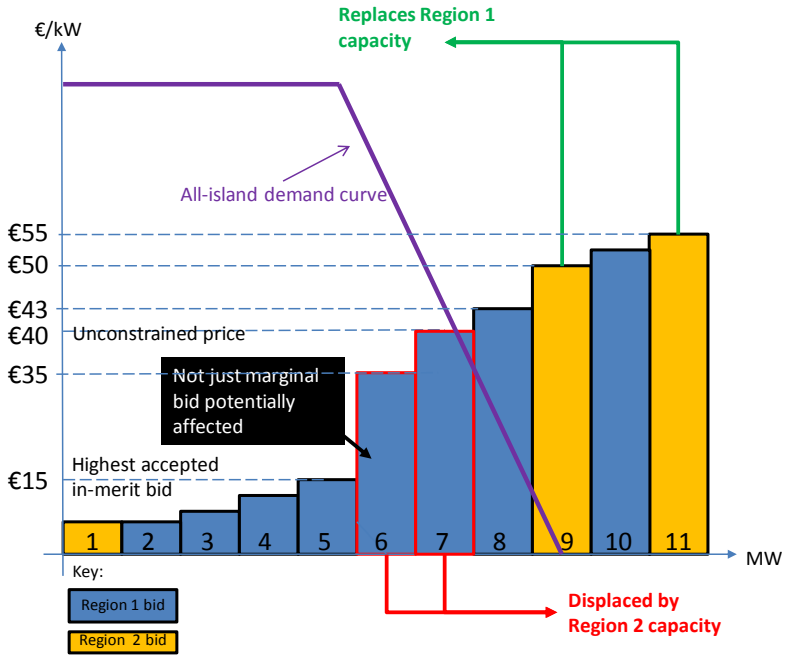
[27] Albeit even in that case it should find a better solution that a heuristic.

auction are not awarded a Reliability Option because other, more expensive bids in Region 2 must be accepted to meet locational constraints.

3.3.5 In this simplified worked example, all units are the same number of MWs, and a minimum of 3 units are needed in Region 1 and 3 units are needed in Region 2. Figure 2, illustrates the bids stacked in merit order, and the demand curve. The blue bids are located in Region 1, and the orange bids are located in Region 2. In this example, in the absence of constraints, Bid 7 is the marginal bid. The unconstrained price, if there were no inflexibility or locational constraints, would be €40/kW/year. However, only Bid 1 is in-merit in Region 2. To meet the locational constraint of having a minimum of 3 units in Region 2, the CRM Delivery Body has to accept Bids 9 and 11. Let us assume that this result in Bids 6 and 7 not being awarded Reliability Options (whether due to the application of a heuristic rule, or a full combinatorial optimisation). The highest accepted in-merit bid price is €15/kW/year.

3.3.6 In this example, Option 1 results in the clearing price being set at €40/kW/year, whereas Option 2 result in the clearing price being set at €15/kW/year. Bids 1 to 5 are paid the clearing price, and Bids 9 and 11 are paid their respective bid prices, €50/kW/year and €55/kW/year respectively.

Figure 2: Clearing price example



3.3.7 In the above example, the constraint was a locational constraint. However, the relevant constraint could also be an inflexibility (lumpiness) constraint, or a combination of locational and inflexibility constraints. In practice it might not be possible to attribute a single constraint to causing a particular outcome. In any event in the above example, even if there were no locational constraints, if Bid 7 was inflexible, it may be rejected if social welfare is greater without it. In such a case, the highest accepted bid would have been Bid 6, and Under Option 2, the clearing price would be set to the Bid 6 price.

3.3.8 Advantages of Option 1 include:

- The capacity price is likely to be a better approximation to the long run marginal cost of capacity (if bidders bid truthfully), and therefore a more efficient investment price signal. By contrast, under Option 2, if there are material locational constraints, which cause the marginal and some infra-marginal units (in the unconstrained merit order) not to be accepted, this could cause the market clearing price to be significantly reduced below the long run marginal cost- as per the above hypothetical example.
- It tends to reduce the impact of pay-as-bid pricing on infra-marginal bidders and as such creates stronger incentives for cost-based bidding, like for Bids 1 to 5. Under Option 2, Bids 1 to 5 might have an incentive to bid all the way up to Bid 6 price, if they have a good understanding of the cost structures of other bidders, and the likely merit order. However, this incentive is mitigated under Option 1.

3.3.9 Dis-advantages of Option 1 include:

- There may be some gaming opportunities for some bidders such as Bids 6 and 7, if they know or suspect that they are going to be constrained-off, but think that they may set the unconstrained market price. For instance, if Bid 7 is in common ownership with any of Bids 1 to 5, and Bid 7 knows that there is a high probability it is going to set the unconstrained price it might as well bid high. In fact, it has nothing to lose if it miscalculates and bids higher than Bid 8- assuming there are no constrained-off payments. If it bids up to the price of Bid 8 (€43/kW/year), it will drive the market price up towards €43/kW/year, and earn more revenue on the rest of its portfolio. If it bids above Bid 8, Bid 8 will still set the clearing price at €43/kW/year, and Bid 7 will still earn nothing.

3.3.10 The key advantages of Option 2, include:

- It results in lower customer bills, at least in the short term as per the above hypothetical example where the clearing price is €15/kW/year as opposed to €40/kW/year - which is the flip-side of systematically biasing the price downwards. However, it is not clear that this will result in a long term gain to consumers – to the extent the mechanism produced inefficient price signals for new investment it could be expected to increase consumer costs in the long term;
- It does not create the gaming incentives on Bids 6 and 7 identified above.

3.3.11 Disadvantages of Option 2 include:

- Option 2 could create a systematic downward bias in the clearing price resulting in a price which does not reflect long run marginal cost. That being the case it may result in less efficient entry (and exit) decisions, and potentially greater price volatility;
- It might create incentives, that wouldn't have existed otherwise, for Bids 1 to 5 to bid above-cost.

3.3.12 The SEM Committee seeks feedback on which of the two options stakeholders consider appropriate, and why.

3.4 UNSUCCESSFUL IN-MERIT BIDDERS

3.4.1 The SEM Committee decided in the CRM 3 Decision Paper that auction winners whose bid price is greater than the market-clearing capacity price will be paid-as-bid. The paper did not discuss whether any bid would have been accepted on an unconstrained basis (i.e. are in-merit) should be compensated. They could be unsuccessful due to locational constraints and/or inflexibility constraints, even though their bid price is less than the auction clearing price. We can envisage the following compensation options:

- Option 1: No compensation;
- Option 2: Compensation based on "lost profit". May at first sight, appear similar to that which applies in the energy market, although as we discuss below, the parallels are limited. In the existing SEM energy market, any bidder who is constrained-off is paid the unconstrained market price minus the bid price. For instance, in the above example in Figure 2, if Clearing Price Option 1 (unconstrained price) was used then Bid 6 would receive compensation of €5/kW-year[28].
- Option 3: Compensated by "pay-as-bid". Under this option, Bid 6 would be paid €35/kW/year, and Bid 7 would be paid €40/kW/year.

3.4.2 The arguments in favour of compensating a constrained-off bid (either Option 2 or 3) are:

- Equity: arguably, it is not an existing generator's fault that it is located in an area with excess capacity, and not its fault that transmission constraints exist. Compensating constrained-off capacity will reduce the prospect of "unhappy losers";
- Efficiency: if the constraint is only temporary, there may be efficiency gains in incentivising capacity not to close, if it is to provide cheaper deliverable capacity once the constraint has been alleviated. However, arguably Option 2, based on "lost-profit" would be insufficient to allow the relevant capacity to cover its missing money, and may lead to closure anyway. In the above example, Bid 6 would only be compensated €5/kW/year, whereas if it bid was cost reflective, its missing money is €35/kW/year. If the capacity closes anyway, the Option 2 compensation payment would just be a deadweight loss. To be reasonably sure the capacity does not close, it will need to be paid its missing money, i.e. its Bid Price (Option 3).

3.4.3 The key drawback of Option 3 is the cost to the consumer, at least in the short term. It may cost the consumer only slightly less than Option B in Section 3.2, under which the capacity secured to meet locational constraints would be additional, no plant would be constrained-off, and by implication the capacity in question would receive the clearing price. At least in option B, there are obligations associated with the RO, while in option 3 they would not be subject to difference payments.

3.4.4 Another key issue with Options 2 and 3 is State Aid. This option might face significant difficulties regarding compliance with State Aid restrictions. Effectively it could be construed as payment for a service which the generator is then not able or obligated to provide.

[28] €40/kW/year clearing price – Bid 6 price of €35/kW/year

3.4.5 A key advantage of Option 1, is clearly the saving to the consumer- at least in the short term, it is not paying for undeliverable capacity. Another key advantage is that it pays for the capacity for which it has been determined there is a need – specifically, capacity that is in the right location – and doesn't pay for capacity that is not needed, or for which the value exceeds the cost. In the long term this is perhaps the most fundamental feature of efficient pricing.

3.4.6 A preliminary evaluation of the options suggests that Option 1 is favoured. Option 2 may result merely in a deadweight payment to the bidder with no efficiency benefits, whereas Option 3 could impose a certain and significant cost on consumers, which is not guaranteed to payback in subsequent years.

3.5 REPRESENTATION OF CONSTRAINTS

3.5.1 Under any auction design option it will be necessary to define the constraints that apply. The preferred methodology should have constraints that are transparent and published in advance of the auction, such that the process of winner determination could be easily replicable.

3.5.2 In all auction design options, it seems evident that the workability of the option, and the effectiveness of the CRM in general, is adversely impacted if too many constraints are incorporated. Taking locational considerations into account in the CRM could produce reasonable results and be effective if restraint is exercised in setting locational needs. However, if the CRM was used as a transmission backstop to try to get generation that works in all ways with existing transmission, without any allowance for some possible transmission modifications, it could easily degenerate into a situation where location trumps all other factors. One or two constraints might be workable, depending on the option, but more would be difficult to accommodate.

3.5.3 There is a question of how locational capacity delivery constraints should be numerically represented. In the SEM there is a history both of expressing them on a unit basis (for example "X out of Y units in this location are needed") and on a MW basis (for example "there should be at least X MW of capacity located in {name of zone}"). The SEM Committee are inclined towards a MW basis for expressing constraints, as this is a metric which is directly comparable to the metric with which load is measured when determining what is necessary to meet a defined security standard. It is a metric which recognises that a larger generating unit does more to resolve a capacity constraint than a smaller generating unit. It is also likely to be a simpler metric, and less susceptible to gaming. However it is recognised that this is a complex issue and consultation responses are invited on this point.

3.5.4 There are a number of options regarding the means by which locational capacity adequacy constraints could be represented in the auction winner determination process:

- **Option 1:** A separate capacity requirement for each constrained capacity area, *measured in MW.*
- **Option 2:** A separate capacity requirement for each constrained capacity area, *measured in units* (albeit the overall target for the whole market would still be measured in MW).

- **Option 3:** Nested capacity areas (with capacity requirements specified in MW).

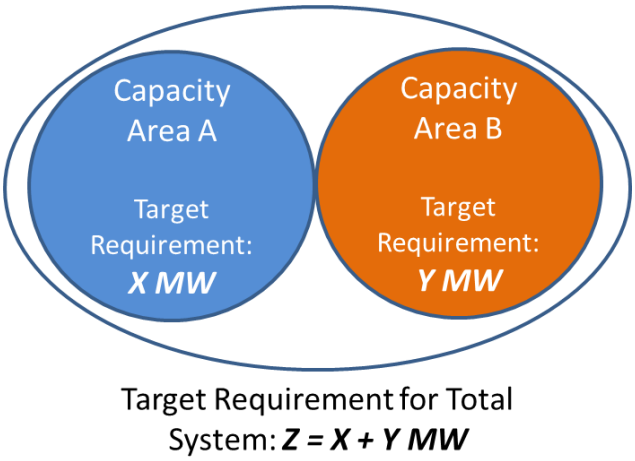
3.5.5 There is a close linkage between the winner determination options and the constraint representation options and for that reason the constraint representation options are described below in that context. The most obvious example is winner determination Option A (ex-ante identification of must-have units). In that case, none of the constraint representation options are relevant since locational issues are instead solved on a unit-by-unit basis prior to running the auction. To a similar extent the same is true of winner determination Option E (ex-post TSO system security analysis to identify must-not exit units) since in this case relevant locational issues are addressed within a TSO system security analysis ex post. For these reasons, winner determination Options A and E are not considered in the descriptions and illustrations that follow.

3.5.6 For simplicity in the descriptions and illustrations that follow it is assumed there would be two capacity areas (Capacity Area A, and Capacity Area B) that make up the island of Ireland.

Option 1 (Separate capacity requirements by constrained capacity areas, measured in *MW*)

3.5.7 Option 1 would involve setting a capacity target of X MW for Capacity Area A, and a capacity target of Y MW for Capacity Area B. In principle, X could be established with the knowledge that Capacity Area A could be supported to some extent by Capacity Area B, if necessary, and so X might even be set at a level less than A's forecast peak load. The same principle could apply in reverse, and in theory Y could be less than the B's peak load. However in practice it should clearly be the case that X+Y MW must be sufficient for the island as a whole, in which case it might be necessary to determine X and Y on an almost independent basis. X+Y MW would represent the target requirement for the system, which is a key parameter in the CRM demand curve.

Figure 3: Constraint Option 1



3.5.8 The application of this option could differ depending on the winner determination option chosen:

- **Under winner determination Option B (additional capacity)**: X and Y would potentially be deemed as hard constraints. If, after applying the unconstrained merit order either X MW

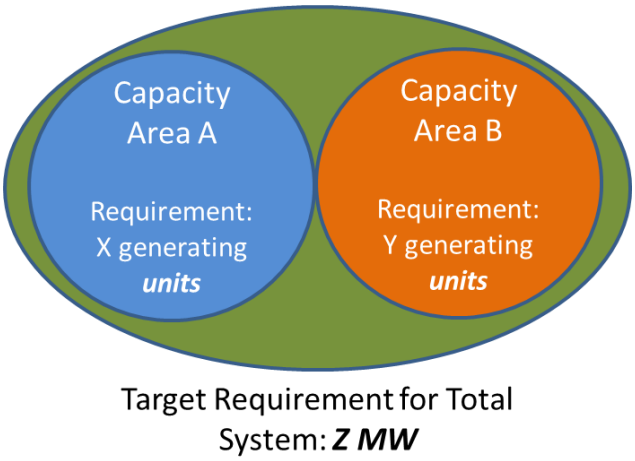
was not selected in Capacity Area A or Y MW was not selected in Capacity Area B, then additional capacity would be selected in the deficit area.

- **Under winner determination Option C** (**heuristic approach**): It would be possible that X and Y could be treated as hard constraints, like under Option B. Another alternative is that for Step 2 of Option C, two demand curves could be used where X is the target quantity on the demand curve for Capacity Area A and Y is the target quantity on the demand curve for Capacity Area B. (The two demand curves added together would equal the demand curve used in Step 1 of Option C.)
- **Under winner determination Option D** (**combinatorial approach**): Separate demand curves would be established for the two Capacity Areas, and X MW and Y MW would represent the target quantity on each. To the extent there are hard constraints in either Capacity Area, these could be represented by inelasticity in the demand curve(s) concerned.

Option 2 (Separate capacity requirements by constrained capacity areas, measured in *units*)

3.5.9 Option 2 would involve setting a requirement for at least X *units* in Capacity Area A, a requirement for at least Y *units* in Capacity Area B, and a target for Z *MW* would apply for the system as a whole. All three constraints would simultaneously apply, and Z MW would represent the target requirement in the CRM demand curve for the system as a whole.

Figure 4: Constraint Option 2



3.5.10 The application of this option could again differ depending on the winner determination option chosen:

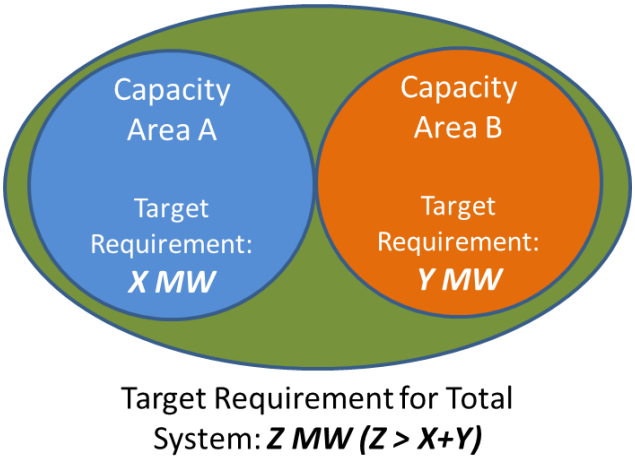
- **Under winner determination Option B (additional capacity)**: Like under Option 1, X and Y would likely be deemed as hard constraints.
- **Under winner determination Option C** (**heuristic approach**): The CRM demand curve would be measured in MW, so a generating unit-based metric would not translate to the demand curve. So like for Option B, X and Y would likely be deemed as hard constraints.
- **Under winner determination Option D** (**combinatorial approach**): Again, a demand curve approach would not be applicable to Capacity Areas A and B, so the optimisation

procedure would instead contain hard constraints that at least X units must be selected in Capacity Area A and at least Y units in Capacity Area B.

Option 3 (Nested capacity areas, with capacity requirements specified in MW)

3.5.11 Option 3 would involve setting a capacity target of X MW for Capacity Area A, a capacity target of Y MW for Capacity Area B, **and a capacity target of Z MW for the island of Ireland as a whole**. Now X could be established with the knowledge that Capacity Area A could be supported to some extent by Capacity Area B, if necessary, and so X might even be set at a level less than A's forecast peak load. Likewise Y might be less than the B's peak load. This is possible because the overall capacity adequacy of the island is ensured by setting Z to the capacity target of the market as a whole. As a result, Z should be greater than X+Y. Since Capacity Area X is a subset of the area for which Z applies, and likewise for Y, and since the constraint for all three areas is represented in the same unit of measurement – i.e. MW – this methodology is known as having *nested* capacity areas.

Figure 5: Constraint Option 3



3.5.12 The application of this option could once again differ depending on the winner determination option chosen:

- **Under winner determination Option B (additional capacity)**: Like under Option 1, X and Y would likely be deemed as hard constraints. Z would be used as the target quantity in the demand curve applied to the unconstrained merit order in Step 1 of Option B.
- **Under winner determination Option C** (**heuristic approach**): As for Option 1. Z would be used as the target quantity in the demand curve applied to the unconstrained merit order in Step 1 of Option C.
- **Under winner determination Option D** (**combinatorial approach**): Separate demand curves would be established for Capacity Areas A and B, and X MW and Y MW would represent the target quantity for each. To the extent there are hard constraints in either Capacity Area, these could be represented by inelasticity in the demand curve(s) concerned. A further demand curve would apply to the island as a whole, with a target quantity of Z MW.

3.5.13 Under any of these options, Z would be used as the target quantity in the demand curve applied to the unconstrained merit order for purposes of clearing price determination.

Summary preliminary view

3.5.14 Compared to Option 1, Option 3 allows the X and Y parameters to be minimised so that they only reflect the impact of local constraints and nothing more.

3.5.15 Under Option 1 by way of contrast, it is necessary to set X and Y high enough so that (X plus Y) is in total sufficiently high to ensure the overall capacity adequacy of the island. These approaches run the risk of over-stating locational constraints (that X must be located in Capacity Area A, and that Y must be located in Capacity Area B) as a result. Option 1 may therefore have efficiency disadvantages.

3.5.16 The United States has some history of using a variation of Option 1, however a key factor to correct for the potential of overly-constraining the location of installed capacity was to allow bidders from "export" capacity areas to sell capacity into constrained "import" zones, up to predefined transmission transfer capability levels. This required a system of transmission rights which may be unsuitable for the I-SEM.

3.5.17 Option 2, the unit-denominated option, does not have international precedent as far as the RAs are aware. However, it might have some applicability to the I-SEM since it does represent a method which the TSOs have used at times to characterise locational constraints, as described in Section 2.3.

3.6 SUMMARY OF QUESTIONS

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

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

3.6.3 Should a bidder that would have been accepted in an unconstrained auction but which is not awarded an RO receive a "constrained-off" payment in the CRM? If yes, how should the "constrained-off" payment be determined, and why?

3.6.4 How should local capacity deliverability constraints be defined?

4. LONGER TERM CONSIDERATIONS

4.1 ISSUES FOR THE LONGER TERM

4.1.1 The preceding sections of this consultation paper have not placed strong emphasis on whether the inclusion of locational capacity delivery constraints in the CRM would occur in T-1 auctions, T-4 auctions, or both. This section explores this issue in more detail.

4.2 T-1 AND T-4 AUCTIONS

4.2.1 To the extent that locational capacity delivery constraints are applicable in the CRM, these are expected to be applicable to at least the T-1 auctions. If locational capacity delivery constraints bind in the T-1 timeframe (i.e. if constraints are identified which will bind one year ahead) then few tools are at the disposal of the TSOs and the market in general to ensure capacity adequacy other than to ensure that necessary generating units in capacity-constrained locations do not close prematurely because of timelines to build new generation or transmission.

4.2.2 The T-4 timeframe presents a potentially different situation however. If constraints are identified which will bind four years ahead then there may be sufficient lead time to explore other options, as alternatives to explicitly placing locational capacity delivery constraints in a single capacity zone T-4 auction. These other options, designed to address ensuring locational issues, could involve further modifications to the market arrangements, and/or they could involve TSO-led transmission initiatives. Options are set out in Section 4.3.

4.2.3 Separately, there is an issue related to the *timing* of T-1 and T-4 auctions. In accordance with the CRM 3 Decision Paper (SEM-16-039), T-1 auctions are anticipated for two purposes:

1. For each of the transitional years to cover the period up to the Capacity Delivery Year of the first T-4 auction; and
2. As an adjustment mechanism for each year in the enduring solution, to refine the capacity provision for the following year that should have mostly been secured already with a preceding T-4 auction.[29] This is expected to also include an adjustment for the volume withheld from the corresponding T-4 auction.

4.2.4 It follows therefore that T-4 auctions will be interspersed by T-1 auctions. During the transition period there will general be two auctions per year, one T-1 and one T-4, both for close to the full system requirements. After the transition there will still be two auctions per year, albeit the size of the T-1 auction will fall, as it will only be used to secure residual requirements. If the T-1 auctions accommodated locational capacity delivery constraints and the T-4 auctions did not, there could be potential for some complexity and/or inconsistency – at least over the transitional period – albeit these issues would not likely be insurmountable.

[29] [The capacity requirements first addressed by the T-4 auction might potentially also have been supplemented by subsequent T-3 and T-2 auctions.]

4.3 OPTIONS FOR T-4 AUCTIONS

4.3.1 There are a number of options for consideration of locational capacity delivery constraints in the CRM T-4 auctions:

- **Option 1 (Constraints in T-4)**: *Do* apply locational capacity delivery constraints in the CRM for the initial and enduring T-4 auctions.
- **Option 2 (No constraints in T-4)**: *Do not* apply locational capacity delivery constraints in the CRM for the T-4 auctions**.**
- **Option 3 (Constraints in T-4 on transitional basis only)**: *Do* apply locational capacity delivery constraints in the CRM for the T-4 auctions, but transition them out over time.

4.3.2 Option 1 (constraints in the T-4 auction) is certainly the most conservative option in the sense that it provides the most in the way of tools to ensure system security. This has the benefit that if locational capacity delivery constraints do not bind in the longer term (perhaps in part because of wider locational signals) then the mechanism can naturally "sunset". I.e., if the constraints no longer bind then they will no longer impact the auction and the auction would occur as if the constraints were never provided for in the first place. Under this option the signal to potential new generation investors is higher out-of-merit winning bids (which are paid as bid and arguably less transparent) being accepted in the capacity import location as compared to the capacity export locations.

4.3.3 Options 2 and 3 rest on the assumption that at some point – either from the outset of the I-SEM, or some point in the longer term – it will not be necessary to explicitly include locational capacity delivery constraints in T-4 auctions. A key issue for consideration is the set of circumstances or criteria that should be required before conducting T-4 auctions without explicit consideration of locational capacity delivery constraints. These conditions or criteria could be ones that are tested today, and they could be continuously re-evaluated over time.

4.3.4 A factor to consider in the evaluation of these options is that, given that the *first* T-4 auction will occur *after* the first T-1 auction, it may be desirable to defer a decision on the nature of T-4 auctions until after learnings have been obtained from that first T-1 auction. The key learning would of course be the extent of binding constraints, and the extent of any system security consequences associated with the winning set of bids.

Wider considerations:

4.3.5 As set out in CRM Decision 1 (SEM-15-103) the SEM Committee may also separately consider a review of GTUoS locational price signals to strengthen signals for where new entrant generating units should locate and where existing plant should exit.

4.3.6 Related to this it is also recognised that in order to fully address longer term locational constraints, consideration will need to be given as to how any approach interacts with incentivisation of TSO transmission build, such that the most efficient means of solving locational constraints is delivered for consumers.

4.3.7 In addition to the proposals described above, if constraints are enduring and are expected to continue to bind on a more persistent basis, consideration will need to be given as to whether it is desirable and appropriate to establish more than one capacity zone. This would need to be considered in the context of the bidding zone review process under the Capacity Allocation and Congestion Management (CACM) Regulation.

4.4 SUMMARY OF QUESTIONS

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

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

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

5. LOCAL SECURITY OF SUPPLY AND MARKET POWER

5.1 BACKGROUND

5.1.1 In CRM Decision 3 (SEM-16-039) the SEM Committee set out its range of measures to mitigate market power in the CRM auctions. The framework of market power controls was comprehensive, and in addition to mandatory bidding (addressed in CRM Decision 1) included:

- An Auction Price Cap, to apply to all bidders, including new build plant;
- A Price-taker Offer Cap which would apply to all existing generators. This Price-taker Offer Cap would generally be uniform, but individual generators could bid to be allowed to have a higher unit specific price cap on the grounds of higher Net Going Forward Costs;
- A sloping demand curve, which would also serve to mitigate market power.

5.1.2 Whilst this framework is comprehensive, with controls on all generators, it:

- Assessed market power on an all-island basis, without reference to transmission constraints; and
- Did not consider certain specific issues arising from the interaction of solutions to address local capacity requirements.

5.1.3 In this section we explore whether the CRM framework as currently designed is sufficient to mitigate any additional issues that arise as a result of local security of supply, or whether additional controls are required.

5.2 ADDITIONAL MARKET POWER ISSUES (EXISTING PLANTS)

5.2.1 The application of a Price-taker Offer Cap to all existing generators set out in CRM Decision 3 (SEM-16-039) goes a long way towards mitigating the market power of all generators in the capacity market. Any generator required for local capacity deliverability reasons which seeks a higher capacity payment than the Uniform Price-taker Offer Cap will have its application for a higher unit specific bid limit closely scrutinised. The SEM Committee will only allow it to bid above the Uniform Price-taker Offer Cap where it is able to demonstrate that its bid reflects its Net Going Forward Costs.

5.2.2 Nevertheless, there are some consequences of the local security of supply requirement, that are worthy of further consideration. For example, is there greater potential for a generator required for local security of supply to exercise market power up to the Uniform Price-taker Offer Cap?

5.2.3 In an unconstrained system with excess capacity, we might expect the capacity price to clear well below the regulated Uniform Price-taker Offer Cap, with clearing prices tending to zero where the over-supply is large. Whilst the Uniform Price-taker Offer Cap has not been set yet (it will be set as part of the CRM Parameters consultation), it is envisaged that it will be higher than the Net Going Forward Costs of the majority of plant on the system.

5.2.4 Where a generator has local market power due to the constraints, it has an increased ability bid up to the Uniform Price-taker Offer Cap and be accepted out-of-merit, even in a market with significant over-supply at an all-island level. If it has local market power, its bids are not as effectively constrained by competitive pressure as they are elsewhere on the island.

5.2.5 In principle, it would be possible to place restrictions on the bids of any plant required for local security of supply reasons, such as:

- At its individual Net Going Forward Cost, i.e. below the Uniform Price-taker Offer Cap if its individual Net Going Forward Costs are lower than the Uniform Price-taker Offer Cap; or
- At the Uniform Price-taker Offer Cap adjusted for any specific ancillary service payment it may receive.
- Any individual plant could be required to have an evaluation of its Net Going Forward Costs due to fear of economic or physical withholding, at the discretion of the SEM Committee.

5.2.6 The SEM Committee seeks feedback from stakeholders on this point.

5.3 ADDITIONAL MARKET POWER ISSUES (NEW PLANTS)

5.3.1 A separate locational market power issue relates to new plants. Of particular concern is the situation where a long-term pay-as-bid capacity contract could be awarded to a new plant in a constrained location under conditions that were less than competitive.

5.3.2 Partly the issue is that not all of the market power mitigation mechanisms set out in the CRM 3 Decision apply to new plants. Mandatory bidding would not, of course, apply to new plants. New plants would not be subject to the Price-taker Offer Cap. New plants would however be subject to the Auction Price Cap.

5.3.3 The use of sloping demand curves can contribute to mitigating market power to some extent, compared to using an inflexible representation demand. However the existence of locational constraints could more than offset this mitigation. The existence of locational constraints would tend to make the CRM auction less competitive because the effective market within each constrained area would be smaller and thus more highly concentrated.

5.3.4 Further exacerbating the market power issue as it relate to new plants is the fact these plants can have a very different competitive dynamic compared to existing plants:

- A new plant can obtain a contract of up to 10 years, as opposed to an existing plant which can only obtain a contract for one year. Whilst the scope for new entrants who will meet the significant financial commitment threshold, entering into the transitional auctions is limited, it is possible. The ability to earn a 10-year contract means that new plants can have a much greater incentive to exert market power. Exacerbating this point even

further, the auction will not take into account the duration of the contract,[30] so the long-term cost to consumers of accepting a high-priced bid is in large part ignored in the winner-determination process.

- Prospective new plants are in practice likely to face considerable barriers to entry, especially compared to existing plants which – by definition – have already entered. When there are high barriers to entry, those who are able to enter often find themselves with pricing power because of the lack of competition they face from other prospective newcomers. This point was discussed in CRM 3, and the barriers include such factors as: a limited number of sites; limited fuel availability options; limited grid connection options; issues associated with planning permissions; competition issues over siting; and so on.

- The "market" as it applies to new plants is inherently less competitive than for existing plants because new plants face costs and risks of entry that have already been sunk in the case of existing plants. The process could have similarities to an IPP procurement process in which the level of competitiveness can never be taken for granted. A considerable financial commitment can be expected to be required, to reach the point where a bid is placed for a new plant in the auction. Much of the infrastructure arrangements, financing, siting and so on would need to be in place and a full business case established before an entity would commit to a bid. In practice this limits the number of new entry bidders than can be expected – particularly if only one or even zero contracts for new entry might be awarded as a result of the auction.

5.3.5 In sum then: key market power mitigation measures do not apply to new plants; new plants may have much stronger incentives to exert market power than existing plants; and at best the competition between prospective new plants in the auction can be expected to be limited. The concern is that the existence of locational constraints could considerably exacerbate this already-difficult competition situation as it relates to new plants.

5.3.6 In beginning to address this concern it is worth considering what a "market power strategy" from a prospective new entrant in a constrained location might look like:

- One possibility is that an existing generator might specify that a plant will close (as it may elect to do within the T-4 timeframe) and then bid in a new plant to the T-4 auction, perhaps at a different site, which would effectively replace the old one. The bid for the new plant might be at a high price – i.e. above its costs and above a reasonable return on equity, as long as the price is at or below the overall Auction Price Cap. At face value this could appear to be a logical upgrade for operating efficiency reasons.

- Another possibility is that a new entrant bidding in a constrained area might simply offer a high price – just taking advantage of the lack of competitiveness in that area to obtain a high-priced contract. At face value this appears to be reasonable: we would rather have

[30] Refer to CRM 3 Decision, page 8: Winners will be determined based on the price and quantity offered, and as if the duration of all bids is 1 year, i.e. there will be no adjustment for Reliability Option price fix length.

more bids than less, after all. But if the result is long-term contracts awarded on a pay-as-bid basis without a sufficiently competitive process then there would be a concern.

5.3.7 It should be emphasised that the issue here is not *whether* locational constraints should be recognised or not in the CRM auction arrangements. Rather, the RAs' view is that any constraints must be recognised and dealt with from a market power perspective, one way or another, to the extent they exist and to the extent they represent part of the underlying structure of the market.

5.3.8 The SEM Committee recognise this is a difficult issue and in a wider context transmission solutions should not be left unconsidered in the event that multi-year pay-as-bid new plant bids would otherwise be accepted in a CRM auction (either T-1 or T-4). I.e. before accepting such bid for a constrained location it is reasonable to confirm first that a transmission solution to relieve the constraint would not have been a lower cost solution for consumers.

5.1 SUMMARY OF QUESTIONS

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

6. NEXT STEPS

6.1.1 Interested parties are invited to respond to the consultation, presenting views on the options set out in this paper and where applicable any minded to positions that have been expressed proposals and discussion in this paper.

6.1.2 Responses to the consultation paper should be sent to Karen Shiels (Karen.Shiels@uregni.gov.uk) and Thomas Quinn (tquinn@cer.ie) by 17:00 on Thursday 22nd September 2016.

6.1.3 Please note that we intend to publish all responses unless marked confidential. While respondents may wish to identify some aspects of their responses as confidential, we request that non-confidential versions are also provided, or that the confidential information is provided in a separate annex. Please note that both Regulatory Authorities are subject to Freedom of Information legislation.