Merin Joseph
Commission for Regulation of Utilities
The Exchange
Belgard Square North
Tallaght
Dublin 24
mjoseph@cru.ie

Donna Maye
Utility Regulator
Queens House
14 Queen Street
Belfast
BT1 6ED
Donna.Maye@uregni.gov.uk

04 November 2022

RE: SEM-22-054 - Call for Comments on the EY Review of the Performance of the SEM CRM (the 'Call for Comments')

Dear Merin and Donna,

1. Introduction and summary asks

Bord Gáis Energy (**BGE**) welcomes the timing of this Call for Comments. It represents a valuable opportunity to address certain shortcomings in the current CRM design, the improvement of which could mitigate the persistence of the ongoing security of supply crunch and offer a degree of regulatory certainty around current CRM signals for the remainder of its lifetime. In this response we do not advocate for radical adjustments of the design, rather we urge the Regulatory Authorities (**RAs**) to consider relatively "quick-win" low intrusive (systems and time wise) adjustments that work within the confines of our current state aid approval. We note at this point the parallel ongoing consultations on the Best New Entrant and the Capacity Requirement. These are critical areas that need revision. We have touched on the capacity requirement matters here but ask the RAs to review our further submission next week on that also, in tandem with proposals here. BGE's full view on the BNE will be submitted by the deadline at the end of this month. Please take all three of our responses into account when finalising the future changes for the current CRM.

Bearing in mind that an overarching objective of the consultation is to identify issues affecting the procurement of sufficient capacity and make recommendations accordingly, our high-level assessment of the EY review is that although interesting and detailed, it is missing a thread between the various markets where assets earn a return on their investments. The focus of the EY recommendations seem to be on availability of contracted units as opposed to the problem of not getting enough units contracted. It does not address why units – existing and new – are not investing in this market and therefore in our view will not deliver a better market outcome in the long-term.

The reality for generators in the current environment is that the three main revenue streams for non-renewables (energy, system services and capacity) are today sending mixed signals for both the retention of efficient existing capacity and attracting new capacity. The capacity market, both in terms of volume and price has not sent a signal to invest since I-SEM was launched. Looking at system services, the recent proposed reduction of 35% of 5 of the 12 tariffs on top of the 10% reductions in these tariffs last year have completely undermined the role of system services in signalling the type of fast-acting capacity we need for a decarbonised system. Existing generators and prospective units have resorted to assuming a very benign market with commensurate negative assumptions around potential system services revenues.[1] Energy revenues, as recognised by the RAs in the ongoing parallel consultation around the Best New Entrant[2], are becoming increasingly volatile such that from year to year as RES installation grows the level of reliance that units can place on energy as a revenue stream will commensurately weaken.

Within this context of needing clearer signals for investment, the CRM design could be enhanced in BGE's view to deliver sufficient capacity through:

[1] Please see our submission to the DS3 consultation on these proposed tariff reductions dated 14/10/2022. We ask for urgent revision of the calculation of the €235m annual cap to capture changes in assumptions since 2013 and capture that it is a system with 95% SNSP we need to attract services for. In parallel we urgently need to see the detailed design of the new system services market (SSFA)

[2] SEM-22-076 Best New Entrant Consultation | SEM Committee

- Adjustments to the capacity requirement methodology:
    - the interconnector needs to better model the markets at both ends;
    - the requirement should account for reserves, and;
    - the setting of the capacity requirement needs to be more accurate, transparent, predictable, and replicable whereby:
        - EirGrid's Generation Capacity Statement (GCS) should be the source document on which reasonable assumptions on future system needs including demand are based
        - Akin to GB's Future Energy Scenarios approach, the GCS should be subject to industry inputs/ consultation.
        - A consistent belief set should also exist as between the GCS, and EirGrid's Tomorrow's Energy Scenarios and Shaping Our Electricity Future documents and this belief set should be reflective of current DECC policy. We note for example that the current GCS is still reflecting a 70% target so we will not have a realistic view on capacity needs from the GCS for capacity auctions until the 2027/28 T-4. This shortcoming needs urgent addressing so investors can make reasonable assumptions.
        - We need to see reasonable demand and capacity forced outage references in the least worst regrets methodology to enable us to draw inferences on what the annual drivers for capacity volume changes are.

- More appropriate price signals:

    - The capacity and system services market need to work collectively to incentivise investment in the right type of investment. As currently designed, the capacity market chiefly incentivises investment in the cheapest type of capacity. This needs to change so that any new capacity entering the system is contributing not just to our capacity adequacy today but to our overall net zero targets over the coming decades. BGE is responding to the parallel consultation on the BNE, please review that response in tandem with this response for further insights on this point.

In light of these views above, that we need to bring stability and clarity to the CRM as a matter of priority to drive investment (in existing and new plant) to ensure security of supply, BGE was surprised to see the EY report put so much focus on availability as opposed to adequacy. In our view, the suggested remedies would actually make the CRM increasingly risky such that they would dampen investment signals (creating inefficient exit signals with no entry signal). Little recognition was given to how successful the RO has been in providing a hedge on prices for consumers. Neither does the EY report provide sufficient analysis as to the driver for their availability concerns and why high BM prices are not occurring when one would theoretically expect them to. BGE's analysis in section 2 explains why this is the case considering the Irish system is uniquely small, lumpy, and heavily constrained. In essence, our assessment has determined that high BM prices are not materialising mainly due to the high level of constraint actions in the BM, bidding rules, the inherent design of the RO mechanism itself and the effect of volatile RES output on the bidding behaviour of RO contract holders. **We urge the RAs not to pursue these availability related proposals[3] via the CRM as it heightens CRM regulatory uncertainty contrary to what the market and consumers need today**. The risk of RO strike prices occurring still exists and as RES forecasts become increasingly accurate the prospects of strike price events occurring in the day ahead market too increase. Recalibrating the ASP will dilute this potential contrary to what was envisaged during ISEM design. **EY's concerns in our view are more an issue for constraints mitigation and the design of the BM, separate to the CRM.** If EY's suggestions around recalibrating the administered scarcity price (ASP) and re-introducing interconnector volumes into BM pricing proceed, the perception is that the CRM is increasingly risky such that it dampens investment signals (creating inefficient exit signals with no entry signal). There are huge risks also around what an appropriate level to set an ASP/BM reference price to is which would require substantial consultation prolonging the CRM market uncertainty being experienced today. **The concerns raised by EY with respect to scarcity pricing signals would in BGE's view therefore be better addressed through:**

- Introduction of an energy-only BM pricing stack: the influence of constraints on BM pricing must necessarily end as BM prices as envisaged by the European Balancing Guideline (**EBGL**) should reflect pure energy actions used to address the supply/ demand balance in the market. An energy only BM pricing stack would enhance the transparency in real constraint and imperfections costs for consumers

[3] Recalibrating the ASP; allowing interconnectors affect BM pricing

and help with the predictability of the BM as a revenue stream increasing revenue predictability for investors.

- Removal of non-marginal flagging such that the true marginal MW can set the price more in line with how our EU counterparts set prices and how the EBGL envisages BM prices will be set.
- Acceleration of the detailed design on the system services future arrangements (SSFA) to address any perceived impact of the current RO design on flexibility signals in the balancing market.
- Addressing the grid constraints/ bottlenecks through optimising existing grid and applying CBA determined solutions (grid build/ reinforcement/ system services/ technology devices) to improve the grid and mitigate dispatch balancing costs for consumers.

In section 3 of this response, we focus on the relative 'quick wins' we believe can be adopted within current state aid approvals in terms of the capacity requirement methodology. Section 4 concludes our proposals and suggests next steps and the appendix to this response provides a tabulated view from BGE on each of the remedies raised by EY in their report for ease of reference.

2. BGE's views on EY's proposals to arbitrarily increase the BM price to create more RO strike price events

BGE disagrees with EY's suggestion that the RO is not effective because we are not seeing enough RO payback events. The focus on availability rather than on getting sufficient MWs in the ground risks creating inefficient exit signals with no discernible positive signal for investments at a time when the latter is so badly needed.. Furthermore, the RO has been effective in protecting consumers against high spot prices in line with its design. The lack of high BM prices when one might intuitively expect to see such is explainable by our poor grid constraints, bidding rules, increased levels of renewables and somewhat perverse signal inherent in the RO mechanism to want to avoid RO strike price events.

Insufficient evidence has been presented by EY as to where their concerns on the availability (as opposed to reliability in RO strike price events) are coming from. Re-considering 'availability' conflicts with the ISEM decisions around focusing delivery incentives on RO events delivery ('reliability'). We urge EY and the RAs to consider the fact that while the GCS uses historical availability to inform how available units on the system are in general, it is more appropriate to assess availability on the basis of projected availability out to 5 years. An availability trend should be established weighted per technology and average age of technology. This we believe would provide the RAs with a better understanding of why – given most plants today were designed for baseload running and are now seeing more mid merit/peak running which causes more cycling and maintenance needs and costs – availability may be appearing to be low, but the issue will increasingly dissipate as we progress with RES roll out and thermal plant upgrades to adjust to their lower running will be completed. This should dissipate concerns EY and the RAs might have on availability.

From our internal assessment we have discerned a number of reasons why high BM prices do not always coincide with periods of low-capacity margin. The below in our view shows that it is premature to conclude that because units only face losing less than 3% of annual capacity payments if unavailable throughout the delivery year, the RO is not working effectively. Significantly more context, quantitative analysis and rationale is required from EY as to why ensuring availability is now a priority over-- it seems- creating certainty in the CRM design to enable investment signals better materialise.

2.1 Why BM prices are not always as high as theory would suggest

In summary BGE's assessments show that high BM prices are not always materialising during scarcity because:

i. **Locational grid constraints dampen units' desire to bid higher than short run marginal costs (SRMC) when a unit knows or has a reasonable expectation, due to its location, that it will be run for constraint reasons.** When a unit is run for constraint reasons it is settled at its complex commercial offer data (complex COD) which covers only SRMC[4]. There is thus no need or incentive for the unit to submit simple bids above SRMC. The more constraints on the system, as long as constraint actions feed into the BM price, such SRMC priced constraint actions will by their nature under bidding rules dampen the BM

[4] Due to the bidding code of practice determining only SRMC can be recovered

price. The doubling of dispatch balancing costs for 2022/23 vs. 2021/22 indicates that these SRMC settled constraint actions are becoming more prevalent. More benign BM prices are the natural outcome.

ii. **For RO-contracted units that have some uncontracted volumes (due to de-rating factors), the likelihood of the unit clearing the smaller uncontracted volume in the BM is low. This is primarily because the unit will always run the risk of running up against operational constraints and being non-marginal flagged (NMF**) given the small size of SEM and its lumpy nature. NMF leads to Complex COD settlement, eliminating the prospect of earning a return above SRMC which return would be possible if the unit was settled on simple COD terms (and bid at a more competitive, lower BM price). Effectively the extent of constraints on the system heightens the risk that if volumes are bid too high price wise the prospect of complex COD settlement is higher. If the marginal (non-RO contracted) volume of a unit is bid above the RO price in the scenario where the TSO needs the RO-contracted volume plus 1MW if that 1MW is overpriced the unit could risk not be scheduled in its entirety putting its whole RO contract at risk of RO payback.

iii. **When an RO-contracted unit does not get its volumes fully scheduled at the day ahead market (DAM) stage the nature of the market design is such that units will seek to be as competitive as possible in bidding low to get in-merit at the BM stage to earn any high price that might outturn with a view to being able to cover any arising RO paybacks**. Regardless of the volume of competitors, when capacity margins are lower, there is a higher risk the unit will not be scheduled thus it bids low to ensure it is scheduled in case of high outturn prices. This type of scenario is highly likely to start occurring more and more when renewables outturn at the DAM in large volumes but then forecasts reduce closer to real time reflective of the volatility of intermittent capacity. The EY report refers to this as "bunching" (p.47) which we do not find surprising but deem an inherent consequence of the RO design. Higher prices might theoretically only materialise if there is significant erosion of reserve levels and units willing to risk bidding up to or near the RO strike price. Such units tend to be the more speculative players in the market as opposed to RO contract holders.

iv. **When there are tight margins, the net imbalance volume (NIV) can sometimes be in the opposite direction (negative NIV, market 'long'). One would not however expect BM prices to necessarily be high in these instances- in fact when NIV is negative the BM price is often negative** and in such scenarios in practice the energy imbalance can be met. Thus if the BM prices start artificially rising to reflect reserve margins this delinks the BM from being predominantly correlated with signalling satisfaction of the pure energy demand/ supply imbalance. It blurs the line between energy supply/demand being met with energy plus reserves (non-energy) requirements being met. Creating high BM prices triggered by non-energy issues will also have the perverse incentive of undermining the scope for RO strike events over time to occur in the DAM. Based on the capacity deficits predicted in the latest GCS, over time contracted RO units will increasingly have their "reliability" tested at the DAM stage –prematurely intervening in the market via EY's suggested recalibration of the ASP price would undermine this design element of the original RO decisions.

v. **Finally we refer to the concern expressed in the EY report that perhaps portfolio players bid well below the RO strike price, dampening the BM price, to protect other units in their portfolio from being exposed to RO paybacks.** BGE does not understand how preventing this would in practice lead to more availability during scarcity events as by corollary if there was true supply/demand scarcity in the market these units would seek to bid high enough to make a return sufficient to cover off any and all paybacks one would expect. This is another incidence of the understanding of what type of scarcity (energy vs. energy + non-energy) the RO should be protecting against. In line with EBGL requirements BGE contends that it is only a pure energy supply/demand balance that should be driving RO price events.

2.2 Further risks and practical effects of recalibrating ASP to create scarcity events

The recent assumptions around the level of batteries expected to come on the system in the near term indicate that aligning the Administered Scarcity Price in periods of low margin/ amber alerts will become increasingly less impactful in terms of the RAs' aim to assess availability more regularly. The levels of batteries expected under EirGrid's GCS[5] imply that there will be significantly more reserve levels available in the market as compared to today or recent years and so the prospect of reserve levels eroding to the level needed to trigger the ASP is diluted. The prospect therefore of adopting a recalibrated ASP which is certain to undermine

[5] Generation Capacity Statement 2022-2031

efficient existing units and new units' investment signals is also questionable from the perspective of how often in practice it would materialise "to test availability" when reserve margins increase in the near term.

Aligning the ASP with scarcity margins to drive more RO strike price events does not protect units against the ongoing practice of SO-SO trade decisions being taken hours before an amber alert situation occurring. CRM risk is therefore increased. Such SO-SO decisions, while not influencing the BM price, could in practice negate the need for your unit to run. In such scenarios, interconnector actions which are unpredictable and based on the TSO's need to protect reserve levels can lead to available plant being exposed to high RO paybacks with no spot market earnings to cover them through no fault of its own. This heightens investment risk with no corresponding tangible investment signal.

The TSO scheduling and dispatch approach will not allow clear definitions of energy-based scarcity. The TSO takes actions to solve whole system (energy and constraint) issues and so the BM price is not based on energy-only actions. It will be extremely difficult for the TSO to ascertain when the system is under stress from a pure energy perspective. For investors too, understanding when such recalibrated ASP events may occur will not be replicable given the inherently non-transparent nature of TSO actions.

The proposed alignment of the ASP with scarcity/ amber alerts fails to acknowledge the changing generation mix and how practically there is no physical reason why a plant that is increasingly cycled will be able to change its availability status purely in response to a BM signal. It heightens risks of investing under the CRM more so than creating increased availability signals. With RES increasingly displacing thermal capacity at pace, units (often aging, cycling plant in need of upgrade) that would have been designed to run mainly baseload are now running more mid-merit/ peak[6]. These running profiles increase the risk of plants tripping and going on unplanned or forced outages to operate and maintain them at efficient levels necessary to complement the roll out of RES generation. Adding another layer of risk via automatically triggering RO prices when margins are low unnecessarily creates exit signals at a time when significant continued investment in efficient generation is required. No market fix will force increasingly cycled plant to become more and more available.

The BM has nothing to do with a unit's availability and can in practice do little to change this– a unit already has an obligation to bid into the BM under the Trading and Settlement Code and if they do not, and are not scheduled in another market, they risk exposure to BM prices regardless of the level of those prices. Furthermore, units already have incentives to bid into the BM to avoid RO payback risk and to comply with grid code requirements (failing which the risk is breach of licence). BGE is also concerned that the EY assessment has not fully bottomed out on the risks of arbitrarily creating RO strike price events. We firmly believe that the extent to which the TSO must protect reserve levels (and for example choose expensive interconnector imports over local available generation) leaves units, even when fully available, exposed in scenarios when capacity scarcity may exist but a confluence of demand and low margins (triggering the TSOs' protection of reserve levels) mean the unit is not scheduled. This is just one example of a perverse outcome of arbitrarily creating RO strike price events. Exposing units to an arbitrarily high RO payback, which we can expect will be very unpredictable going on past events, despite their availability sends an ineffective signal.

2.3 BGE's proposals on addressing EY's concern around a lack of high BM prices

Instead of recalibrating the ASP and allowing interconnector actions feed into the balancing price, BGE proposes alternative ways to address EY availability concerns. Given the key drivers for why we are not seeing intuitive BM prices when capacity margins are tight relate to constraints and the regularity at which SO-SO trades could be taken for unpredictable non-energy reasons, BGE suggests that:

- **An energy-only pricing stack should be pursued in the near term on an enduring basis and to compensate energy providers (including DSUs) if instructed not to run for system reasons**. The energy only stack would also be a key mitigating factor for developers whose biggest risks are unpredictable triggers for high energy prices driving RO events and unfair exposure to the RO through no fault of the unit. The TSOs' current processes that build up the BM pricing stack are incomplete and do not deliver a BM price that is independent of non-energy actions. This leads to BM pricing outcomes that are sub-optimal and not in line with the EBGL requirements or the I-SEM project's High Level and Detailed Design decisions. We understand that further consultation would need to occur on how the energy stack could be designed but BGE has considered this matter in detail previously and believes

[6] GCS notes that almost 3,000MW of thermal on the system all-island is >20 years old (fig. 3.1)

that it could be done with minimal systemisation. For example an excel approach to determining "gross actions" taken on a unit and the reason for activating the actions on a unit could be undertaken, potentially ex post, to maximise the number of actions in the pricing stack and help mitigate the high risk of non-energy system actions feeding into the BM pricing stack.[7] Compliance with EBGL (Article 30(1)) would also imply that no linkage to non-energy issues like reserves, in terms of triggers for high BM prices, should exist.

- **We also believe that the concept of non-marginal flagging (NMF) is a legacy from the old SEM days and needs to be removed**. Preventing a unit from setting the price due to a unit having a constraint on it is a theoretical approach to setting the marginal price. NMF conflicts with the EBGL requirement for the marginal price setting approach to consider how ex-ante prices are set and for settlement processes to reflect the imbalance situation and the real time value of energy. The European approach to marginal price setting, i.e. using the price of the actual final action that met demand, would comply with EBGL. It would also dilute the risk that units hold back from pricing BM higher due to NMF risk.
- **In parallel, existing grid infrastructure should be optimised and grid constraints addressed**. EirGrid actions as proposed below are necessary in this regard:
    - **A 'heat' map of Ireland that indicates, on an at least 5 years' ahead basis, where the grid capacity is best located should be published**. The cost of connecting in these good grid areas should be lower than connection costs in poor grid areas with a view to signally investment to locate where the grid can best cater for it in terms of offtake and firmness. These connection costs could be mandated to be included in RESS/ system services/ capacity auction bids which should lead to better outcomes for consumers in terms of the value of the capacity they are paying for. TSOs need to be held to account for the accuracy and delivery on map milestones for grid capacity and firmness. The risk and cost of not delivering on firm access when required should sit with the TSO; clear rules should be set out by the TSO on when a unit is protected from RO paybacks when it cannot deliver through no fault of own and developers should also be permitted to have their contract durations respected if delivery on their contracts is delayed through no fault of their own.
    - **BGE suggest that in parallel to the locational heat map, a GCS timeline type map (i.e. 10 year lookahead) could be provided with a data cut-off date closer to the date of publication** to assist potential investors in determining patterns of constraints and improvement needs and project completions, to increase investor confidence. This would address any concerns on the lag between the cut-off date for data used to inform a capacity auction and the timing of that auction diminishes investor confidence and impacts negatively on data results.
    - **BGE advocates also for a CBA to be undertaken at step 1-2 of the TSOs' – 6-step-planning process for grid** to determine, of those areas on the grid that cost consumers most in terms of imperfections charges, what solutions (i.e. reinforcement/ build/ system services/ technological) are optimal from a cost and grid effectiveness perspective.
    - **BGE has suggested on a number of occasions this year, how the Transmission Development Plan (TDP) could be used to outline in detail constraint mitigation plans for the coming years as there is a significant lack of transparency around what the TSOs are doing to alleviate constraints** between now and 2030 notwithstanding a number of TSO incentives centered around constraints alleviation. BGE understands that it is not a fundamental lack of reserves on the island, but rather constraint issues on the system that prohibit the TSO from dispatching these reserves. BGE is concerned that units may be unfairly exposed to RO strike event paybacks when they cannot deliver due to system / constraint issues. We ask for more transparency regarding how constraints affect market outcomes and how reserve requirements are used by the TSO.

2.4 BGE's position on revising the current exclusion of interconnector flows from BM pricing stack

[7] Please see BGE's response to SEM-21-016 consultation on compliance of the SEM market arrangements with EU Electricity Balancing Guideline for further insights. This solution would overall lead to more optimal outcomes including:
- Lower volatility in BM prices which lead to overall lower BM costs for consumers
- Increased BM pricing transparency and enabling better clarity in levels of dispatch balancing costs (DBCs)
- Increased transparency in BM pricing which would help investment signals particularly in flexible units
- More forecastable BM prices would mitigate capacity market - reliability option (RO) payback – risk
- Avoids perpetual modifications on discrete BM pricing issues that do not address the fundamental problem

BGE firmly disagrees with the prospect of reversing any modifications include Mod_02_21 that reverse the fact that SO-SO trades should not be incorporated into BM pricing. The energy-only stack would have to be up and running before this prospect could be considered further. Given the TSO takes actions to solve energy and non-energy issues simultaneously, as long as this approach continues it will never be predictable or transparent to market participants as to why or when an SO-SO trade should rightly be reflected in the BM pricing stack. Given the lack of market coupling on the interconnectors at present too, the predictability (or lack of) of scheduling interconnector flows would only add more to the current unpredictable nature of BM pricing that incorporates non-energy action prices. The high prices seen in September 2021 were down to early TSO interconnector actions driven by a constraint concern (to put more reserves on the system) and we do not see how those outcomes would not re-occur. This would be another bad signal for investments. Instead we suggest the energy-only pricing stack is pursued in the first instance so that when interconnectors do come back into BM pricing it is clearly only when their volumes are used for meeting energy imbalances.

3. Addressing the real problem(s) within the confines of the current RO design

BGE urges the RAs to re-focus their efforts on ensuring that the current CRM stays fit for purpose until at least 2027, by reinforcing and refining the entry signals we need to retain efficient existent investment and to attract new capacity. Volume and price signals must be the immediate priority in our view. Please see section 1 in terms of how the focus really needs to be on getting the right volume and type of capacity in via correct volume and price signals. The obvious challenge to mitigate is the dearth of capacity that is being delivered under the new design, e.g. only ~100MW of the ~600MW gas units contracted between 2018-2021 are still expected to deliver. Our suggests for what needs to be done to address under-procurement of capacity are below.

3.1 The capacity requirement methodology in the first instance could be modified such that:

i. **500MW of reserves should be included in the capacity requirement calculation**. The ASP is triggered at the lowest point on the reserve scarcity price (RSP) curve when the reserve margin hits 500MW, and the price at this first point in the curve is the RO strike price. Seeing as a 500MW volume is deemed low enough to trigger a response from RO contracted parties, we believe it is most intuitive to include the 500MW in the capacity requirement to mitigate insofar as possible the prospect of the equivalent to one large unit on the system falling off it, triggering a scarcity event. It would also go someway to providing the type of headroom or 'contingency' that EY alludes to as necessary in their report.

ii. **Interconnector modelling should better represent the interaction of the SEM with other markets through interconnectors reflecting the generation and flow interplay between the markets across the interconnectors.** Interactions with the SEM can be modelled best using a fundamental model of the GB system (representing each generator in the system) and gradually improving the representation of the continental system. Better representation of these neighbouring markets would allow the prices on both sides of an interconnector to be endogenous variables. Endogenous prices better reflect interconnection operation as interconnector flows will reflect correlated weather and other shared market conditions such as the current security of supply crisis. The consistency in the treatment of variable renewable energy in the calculation of de-rating factors for both SEM and external markets would better reflect the regional proximity of markets and the probability of similar production conditions in both markets, and allow for the export of renewable electricity to be reflected in the export assumption on interconnectors. The modelling of flow assumptions on the Moyle interconnector for example has not always followed the market activities on an hourly directional flow basis, and the growth in wind production expected in the coming years for both the SEM and GB markets could increase the modelling/ operations divergence. We note the decreased de-rating factor assigned to ICs in recent auctions (from 76.8% in the T-4 2025/26 to 46.1% in the T-4 2026/27) and believe the improved modelling would reflect an even truer representation of reliable IC flows. We note also that CEPA in its BNE analysis is of the view that ICs may not be good candidates for the CRM and this merits further consideration.

iii. **BGE believes that we should have two LOLE standards – one for the capacity requirement and one for operational reasons. This should not prove problematic but practical. The capacity market could be run on a 3 hour LOLE for example but the system should not be operated on a 3 hour LOLE**. Consistent under-procurement in the capacity market as well as cancelled contracts and grid congestion issues have led to the security of supply situation we face today in SEM. A 3 hour LOLE for the capacity requirement would mean more generation projects would be cleared in the auctions which would lessen the risk of under procurement and impact of any contract cancellations. However, BGE believe it would be unreasonable to operate the system on a 3 hour LOLE because i) this would lead to a higher reserve requirement which could lead to over procurement of reserves and higher cost to consumer in the longer run, and ii) the level of SNSP on the system will increase significantly over the coming years as heat and transport become increasingly electrified. It would be prudent to maintain a less conservative approach to setting LOLE for the operational requirement as these increases in SNSP may present significant challenges to operate the system on a 3-hour LOLE during times of high SNSP. Having a 3-hour operational LOLE would be detrimental to achieving 80% RES-e. The TSO would have to carry more reserves and ramping product would introduce further constraints into the system at a time when we need to be reducing constraints significantly.

We do however note that we need to strike a balance between over and under procuring. While contingencies for non-delivery, via the above three proposals for example, have merit we need to ensure we don't unnecessarily lock customers into high priced 10-year contracts. We also note EY's reference to the difficulty of complying with the ACER framework of setting the reliability standard due to its interaction with VOLL. We understand that a VOLL consultation is due shortly and that could influence the level at which LOLE is set. Ideally VOLL and LOLE would be considered holistically to strike the balance between cost efficiency and reliability.

3.2 Derivation of the demand curve and RAs' revision of capacity requirements

The methodology used to determine the final, adjusted capacity requirement as produced through the derivation of the demand curve must be more clearly articulated to industry.

Regarding longer term auctions (T-4s) clarity on the extent to which, and how, EirGrid's annual GCS adequacy analysis is factored into the RAs' capacity requirement/ demand curve calculations is required. This would help with forecast-ability of investment needs and overall confidence on security of supply planning. We would also welcome further consideration on whether more clarity and transparency on how the RAs will continue adjusting the capacity requirement in future will occur or will that discretion perhaps be removed?

3.3 The Lag Period for long term auctions between auction results and delivery

This lag period for long term auctions must be at least 4 years. The long-term auctions should be either true T-4s (with at least 48 months between the auction results and the first delivery month) or T-5s. Most of the T-4 auctions have been held as close to the capacity year as possible (i.e., three and a half years). This puts significant pressure on new capacity to deliver on time for the start of the capacity year. Future auctions should be ideally held four and a half years before the capacity year (as allowed under the capacity market code).

3.4 Least worst regrets methodology

We need to see reasonable demand and capacity forced outage references in the least worst regrets methodology to draw inferences on what the annual drivers for capacity change needs are.

3.5 Locational requirements and the unconstrained all-island run

The all-island capacity requirement should be a factor of all locational requirements on the system as it would enhanced its predictability. I.e. the total all island requirement, should not be less than the combined sub-totals of the locational constraint areas. Similarly the Ireland requirement should not be exceeded by the sum of the sub-totals of the constrained areas within Ireland. At present overlaps across areas exist which could lead to over procurement.

4. Conclusion and proposed next steps

In conclusion, we ask the RAs to focus on the opportunity this EY report offers to enhance the regulatory certainty and predictability of revenues that efficient existing and new capacity in SEM so badly need considering in particular where system services signals have gone. We urge the RAs to recap our explanations in sections 1 and 2 above.

The focus must necessarily in our view be on the need to get more MWs in the ground. That is ensuring signals materialise for maintaining efficient existing units and attracting new capacity considering that demand is going to grow in electricity with increased electrification this decade and to 2050's net zero aims.

EY's focus on availability instead of adequacy serves only to undermine investment signals at a critical time in Ireland's security of supply history. The ASP should therefore not be linked to scarcity to artificially increase BM prices with a view to creating more RO events. Interconnector (SO-SO) trades should not find their way into the BM price so long as the BM pricing stack contains a mix of energy and non-energy actions. Otherwise, we will find ourselves more regularly in the situation seen in September 2021 whereby units that were available were exposed to RO paybacks due to the interconnector being actioned over local capacity to protect reserve levels. Please see section 2 above on this issue.

Overall, the main opportunities to enhance investment signals for efficient existing and new units lie in revision of the capacity requirement methodology to better model interconnector flows and account for reserves and lower levels of LOLE and revision of the BNE, to consider a proxy unit that is net zero compatible. Please see sections 1 and 3 above. The EY 'availability' concern needs to be addressed outside the CRM and the use of an energy-only BM pricing stack and focusing on optimising existing grid capacity/ mitigating grid bottlenecks should go some way towards seeing more intuitively higher BM prices naturally occur when margins are tighter.

Longer-term the capacity market and the range and types of technologies it is attracting need to be assessed in the confines of the sectoral carbon budgets which exist. The decisions on how to do so though need to be made in the very near term. Investment decisions today will lead to plant that will endure into the 2050s – it must necessarily be net zero capable capacity. Today's Annual Run Hour Limit (ARHL) factors are insufficient to effect the change in technology type we need or ensure that newly contracted plant is net zero compatible. We also believe there is merit in considering the role of CCGTs in long term security of supply. We note EY's and the TSO's view in this regard and suggest that considerably more credence to their views on CCGT running are given (especially when considered in tandem with carbon sectoral budgets).

Please see the appendix below for our views on the range of specific numbered suggestions outlined in the EY report. Please do not hesitate to contact me should you wish to discuss further.

Yours sincerely,

Niamh Trant
Regulatory Affairs
Bord Gáis Energy

{By email}

Appendix - BGE's views on EY tabled recommendations

1. Was sufficient capacity procured in capacity auctions?

	EY proposed remedy	BGE position
1.1	Move to tighter reliability standard in line with other European markets	BGE believes the capacity market should be run on a 3 hour LOLE but the system should not be operated on a 3 hour LOLE. Consistent under-procurement in the capacity market as well as cancelled contracts and grid congestion issues have led to the security of supply situation we face today in SEM. BGE is supportive of a 3 hour LOLE for the capacity requirement as this would mean more generation projects would be cleared in the auction which would lessen the risk of under procurement and impact of any contract cancellations. However, BGE believe it would be unreasonable to operate the system on a 3 hour LOLE because i) this would lead to a higher reserve requirement which could lead to over procurement and higher cost to consumer in the longer run, and ii) the increasing level of SNSP coming onto the system will provide significant challenges to operate the system on a 3 hour LOLE during times of high SNSP. We need to balance efficiency vs. resilience and ensure we do not unreasonably over procure from a consumer cost perspective however. The LOLE and VOLL (which we understand will be consulted on soon) should be considered holistically in this context.
1.2	Greater transparency of target setting through a panel of technical experts (PTE) assessment of EirGrid recommendations, with findings published, and explanation of process by which GCS forecasts are translated to Target Volume to procure in capacity auctions.	BGE fully supports this proposal and agrees that the enhanced transparency and accountability of the TSOs' forecasting will prove beneficial for investors. We also suggest that the RAs' methodology and rationale for adjusting the TSOs' recommendations is ended or at least clear criteria for when RA discretion is applied are made known, to heighten the transparency and predictability of possible capacity revenue streams for new and existing capacity.
1.3	More explicit accounting of non-delivery in setting target, with two options for implementation: a) Introduce process to monitor progress reports for early indication of non-delivery; OR b) Apply a standardised adjustment to capacity requirement to account for likelihood of non-delivery, review inputs to adjustment % on a periodic basis.	Please see row 1.1 and section 3 of our main response. We ask that the capacity requirement methodology better models interconnector flows and accounts for reserve which is something that EirGrid has long been requesting also. LOLE should be treated on a 3 hour basis for the capacity requirement only, not for operational reasons. The reduced costs of the new CRM compared to pre-2018 CRM have not delivered sufficient capacity and so consumers are paying for this now via emergency generation costs in TUOS and high periodic electricity costs when demand exceeds supply. However a balance needs to be struck and we believe that the measures emphasised in section 3 should be pursued in the first instance.

2: Did capacity auctions attract sufficient participation?

	EY proposed remedy	BGE position
2.1	Greater investment in infrastructure to enable more competitive all-island market and reducing pressure for new build to be situated in particular locations.	BGE strongly supports EY's view that infrastructure investment is urgently needed to enable a more competitive market. We believe that more than the North South interconnector needs to be in focus here. The Irish grid is urgently in need of major investment – we suggest that a CBA needs to be adopted as part of EirGrid's 6-step process (at step 1-2) to determine, of the biggest bottlenecks/ constraints on the network: a) which are costing the most for consumers in terms of dispatch balancing costs, b) which are in locations not already saturated with grid

		issues and limited in scope for competition due to for e.g. ownership concentration, e.g. Dublin area, c) whether a grid build/ system service/ technological wire solution would be most cost-optimal in achieving the end goal of reduced constraints. We have to start focusing not only on diversity of supply in electricity generation but on diversity in location in electricity generation. The latter, location, being dictated by the status of the grid in various parts of the country. We note that the Cork grid has been limited for several years now and may not in a position to e.g. export an additional 200MW outside Cork in the near term at least. BGE asks for a map of Ireland annual publication which shows on at least a 5-year lookahead basis, (so it can be considered in bids by capacity bidders), where the grid is best in Ireland and the cost of connecting generation/ demand should commensurately reflect the need for the generation/ demand to arrive in the area with a view to for e.g. decentralising large demand centres. Please see section 2 of our main response. The ability for the grid to transport capacity to and from locations will come into play but without the necessary locational signals and investor predictability, the investment will not come. In terms of upfront TUOS costs for consumers, grid impacts are causing market inefficiencies at present with concentration of ownership and market power concerns materilaising. There will be a trade off in the enhanced market efficiency that should materialise once the grid is improved. We suggest however that should TUOS increase exponentially that a smearing mechanism, whereby certain increases are recovered for example over 3 years as opposed to 1 year, is adopted but the cost benefit should be fully understood in advance before committing to spend.
2.3	Requirement of new build to have all necessary consents to pre-qualify for auction	We disagree with this proposal. We believe this is a symptom and not the cause of why plants have difficulties in delivering on time. Please see our answers below in rows 3.1 and 3.4 but in summary we believe this requirement would reduce the number of participants that qualify for an auction and therefore reduce the level of participation in the auction and decrease competition. We believe holding the auctions a true >4 years in advance with results >4 years before expected delivery date should be adhered to as was anticipated when the I-SEM project decided on T-4s. We also believe that where incidents arise that are wholly outside the investors control whereby a project could be delayed then the RAs should have discretion on granting extensions – such extensions and the rationale including evidence of a risk being outside the capacity contract holder's control are necessary for regulatory confidence.
Other	Bidding caps existing units	We note EY's conclusion that while bidding rules for existing plant may inhibit price discovery, no evidence was found that the rules prompted existing plant to shut prematurely or contributed to the capacity deficit. We disagree with the assessment that this area has "limited scope for improvement". Decisions made today will have long term repercussions overlapping with our decarbonisation transition years. According to DECC in November 2021, "It will be essential to deliver at least 2 GW of additional gas generation capacity by 2030 to ensure security of supply, underpin our increased renewable targets, and give investment certainty".[8] However market signals are not materialising to the extent needed to ensure investments for enhancing flexibility or the resilience of units for high RES system which will create high recurring fixed costs like O&M for plants investing in increasing resilience of their units.

[8] DECC Climate Action Plan, page 97

		BGE believe it would not be prudent to create additional exit signals for existing efficient plant and the lack of entry signals coming from system services must be resolved. BGE's biggest concern is that given the lack of entry signals coming from energy and system services that capacity markets will increasingly be needed to signal the continuance of efficient existing capacity. Many existing units will have a role to play in the decarbonisation transition as recognised by DECC in November 2021. As the costs of cycling and the related maintenance increase in tandem with increased intermittent RES, we could find ourselves at risk of losing efficient units sooner than expected. This calls for urgent revision of the appropriate BNE choice to ensure existing capacity price caps continue at a reasonable level.

3: Did new capacity procured in auctions get built?

	EY proposed remedy	BGE position
3.1	Increase lead time to at least 4 years from announcement of auction results to start of capacity delivery year.	BGE strongly supports this proposal. We also fully agree with EY's assertion (p. 37) that improved prequalification requirements, more timely monitoring of project milestones and appropriate adjustment to the de-rated volume to incorporate risk into demand-setting are "principally important as long as auction lead times are insufficient for new build projects to get consented and built in". A true T-4 will better address the issue rather than pursuing any of these other ancillary options above.
3.2	Increase performance securities following the auction.	To address any concerns that participants may self-decide to terminate to gain from a subsequent auction clearing at a higher price, further consideration could be given to higher Termination Charges in conjunction with a separate review by the RAs for units who clear in an auction yet terminate their New Awarded Capacity contracts only to bid the same units in successive auction(s) to secure increased payments for the same capacity. This oversight by the RAs could be to review with the developer pre-auction the proposed bid level of the previously terminated unit into the subsequent auction to permit (or not) any increased bid level above the awarded price of the previously terminated award. The RAs review could include whether the previous termination was as a result from "uncontrollable" risks outside the control of the developer (such as non-delivery of grid or gas network connection) as opposed to manageable risks within the control of the developer.
	Require performance security to be lodged prior to auction.	We disagree with this proposal. We believe this is a symptom and not the cause of why plants have difficulties in delivering on time. Several other mitigating measures to non-delivery can be applied in the first instance without unnecessarily undermining investor confidence. More collateral costs could increase bids, affecting consumer costs, and could deter new entrants as EY notes with less access to financing.
3.3	Increased monitoring, with a taskforce involving RAs, TSOs and Govt departments to flag issues and take action to address barriers.	We support this concept. We believe that the regularity of meetings for projects in pipeline development is at a good level now but could benefit from the wider participation of entities to ensure all interested stakeholders are on the same page in terms of delivery risk and that appropriate best endeavours are undertaken to collaborate to mitigate delivery risks.
3.4	More permissive approach to requests for extensions from new build projects.	We believe that the RAs' discretion should not be fettered when it comes to determining whether extensions to contract holders would be better granted if it would mitigate cost impacts for consumers. While considerable discretion may need to be exercised from time to time, provided there is adequate evidence and the risk that materialises is of such an extent that it could not reasonably be foreseen or planned for, consideration to extensions should be permitted. E.g. if a unit may be delayed by 18-24 months but procuring another unit could take >4

		years, it is plausible for the RAs to decide on extensions provided transparent criteria have been applied and decisions are published together with rationale to provide consumers with comfort too as to decisions being made on electricity security. We acknowledge the need to avoid bidders bringing projects to auction with unrealistic timetables in the expectation that extensions will be granted but with the increased performance bonds now standing at €40k/MW and the scope for auction contracts to be reduced if the rationale for delay is not to the RAs' liking, this should deter such behaviour.

4: Was the capacity procured of sufficient value?

EY proposed remedy		BGE position
4.1	Recalibrating the administrative scarcity pricing function so BM pricing better reflects market scarcity and causes a higher frequency of periods with prices above the RO strike price.	BGE strongly disagrees with this proposed remedy. Please see sections 1 and 2 above of our main response. We do not believe that recalibrating the ASP to ensure more RO events occur would "create a more robust incentive to be available and give greater confidence in the reliability of capacity that has been contracted." We need to be fully cognizant of our a) current security of supply situation – a holistic view should be taken on the challenges being faced in energy (lower scope for predictable returns as RES increases) and system services (tariffs being reduced to align with a cap determined for a different system back in 2013), and b) other factors like there being insufficient capacity. The focus should be to incentivise entry, and not add more risk deterring prospective investors and undermining existing efficient units considering their ongoing recurring O&M costs to ensure their units remain resilient. ASP recalibration would add this extra layer of risk. We disagree with the statement on p51 "The effectiveness of the RO mechanism relies on there being sufficient frequency of stress events and severity of penalties for plant that is unavailable". The RO has the incentive of ensuring when prices are high the hedge is there for suppliers – because a perverse incentive might arise from time to time, for reasons explained as being unexceptional in section 2 of our main response, that is not to say the RO is ineffective, sometimes the hedge is ensured by ensuring the spiky price never materialises for the supplier/ consumers. Furthermore, we believe the additional 564MW of battery capacity that has been awarded contracts from the recent capacity auctions for delivery by 2025 should be considered in any decision to recalibrate the ASP function as this shift in the market would mean that scarcity pricing will be less likely to be triggered as the market would be significantly less likely to experience a reserve shortfall. Please see s.2 of main response.

	Refining the principle of flagging interconnector actions from SEM BM prices to drive prices that are more likely to exceed the RO strike price are and more reflective of the value of generation.	BGE robustly disagrees with this proposed remedy. EY itself notes (p48) that the impact of the interconnectors being taken out of pricing was lowest on the spectrum of possible reasons (in EY's view) why BM prices were low when scarcity was high. Incentives to bid below the RO strike price can exist for reasons outlined in section 2 of our response. Furthermore, i) participants with an RO contract have an incentive to keep their price below the RO strike price as to go beyond this with uncontracted volumes would significantly increase the risk of not clearing in the market ii) scarcity in the BM drives competition as there is an incentive to keep price at or below the RO strike price in order to be actioned (as even an additional 1MW uncontracted volume above the strike price greatly increases the risk of not running), and iii) when the strike price is triggered, interconnectors and reserve are called upon which negates the need for participants to be dispatched, which also adds to the risk of not clearing for volumes above the RO strike price. Please see section 2 of our response – the energy pricing stack needs to be introduced and major grid investment and optimising of current grid capacity needs to occur before further consideration to including IC flows in BM pricing should occur.
	Greater monitoring of technology performance in stress events to inform future de-rating factor setting.	One of the suggested advantages of this approach is that it would help ensure more accurate procurement of capacity. BGE believes that this is critical to ensure the right volumes of capacity are procured going forward considering the dearth of new capacity we have seen delivered under the new SEM. We believe however that any measure that might subjectively negatively impact de rating factor settings needs to be treated carefully. Our preference in the first instance to ensure capacity adequacy is that the capacity requirement methodology and LOLE adjustments outlined in section 3 are considered.
	Applying administrative penalties for non-delivery to plants in specific locations where an amber alert has been raised and a plant is unavailable.	BGE is concerned at the level of focus given to availability over adequacy in this report and believe that it raises risks of inefficient exit signals. When stress events are locational it reflects the problem of grid bottlenecks. These bottlenecks must necessarily be addressed with grid investment and improvement options (either build/ market/ technology solutions determined via a CBA) as outlined in row 4.1 above.
	Implement additional physical checks on existing capacity providers in periods with no stress events.	Again the focus on availability over adequacy is very concerning as it raises the risk of inefficient exit signals with no prospect of entry signals, the latter being much in need. All generators have a grid code obligation to be available and make accurate availability declarations. We support the concept of the TSOs ensuring that grid code compliance is occurring.
4.2	Implement baseline methodology for assessing the contribution of DSUs in reducing energy demand.	BGE supports this concept.
	Pay DSUs for negative generation up to the RO strike price.	Yes. We agree with this proposal. DSUs should be on as level a playing field as possible with other capacity.
	Determine energy-only stack within balancing market and compensate energy providers (including DSUs) if instructed not to run for system reasons.	BGE supports the concept of an energy only stack. We believe that it is required in order to be compliant with EBGL. Please see section 2 above.
	Set single derating factor for DSUs regardless of size.	Yes we agree with single derating factors for DSUs regardless of their MW size (though they should differ depending on their response duration).

	Implement provision for secondary trading for capacity providers.	Secondary trading should be facilitated.
4.3	Allow 15-year contracts for the most capital-intensive new build (i.e., CCGTs, long duration storage).	BGE believes that a holistic review of how the revenue streams of energy, system services and capacity interact and work together is urgently needed. The capacity market is signalling investment in the least cost capacity at the time of the auction. However the system services market is needed to signal the type of capacity we need, but this signal is not here today. If we do not start considering how the two markets- DS3 and capacity- can complement each other not only to deliver the volumes needed for adequacy but the type of capacity needed to support a net zero system then we are at risk of not meeting our sectoral carbon budgets and ultimately net zero. These markets needs to start working more in harmony in the very near term as investments today will endure well past when net zero should be achieved. The concept of 15-year contracts for the most capital-intensive new build merits further consideration in this context..
	Making ancillary service contracts more accessible to new build by creating ancillary service contracts with a longer lead-time and duration in line with the CRM and by procuring the products in a single integrated auction process.	We support coordinated timings where appropriate for the products in question, between the capacity and system services markets. Co-optimised procurement is notoriously complex and may delay the development of robust markets on time to enable us meet net zero targets.