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RE: CRU/2023/047 Administered Scarcity Pricing Review Consultation Paper (the "Consultation")

Dear Emer & Lisa,

Bord Gáis Energy ("**BGE**") welcomes the opportunity to respond to this consultation on the Administered Scarcity Pricing ("ASP") Review. While we acknowledge the Regulatory Authorities ("**RAs**") concern that Balancing Market ("BM") prices do not appropriately reflect system scarcity, we believe that there are several contributing factors to this, and we have outlined these in detail below. The options set out in the consultation will not address the issues, and perceived issues, at hand. The implementation of any one of the proposed options will only add unpredictability to the market which will dilute the signal for availability, making it more difficult for dispatchable generation to predict scarcity events.

The lack of high BM prices when one might intuitively expect to see such is explainable by our system design, grid constraints, bidding rules and increased levels of renewable generation. In considering these factors, BGE has been consistent in its view that arbitrarily altering the ASP to align with past system alerts will not provide the necessary long-term investment signals and will not yield the improvements in availability expected by the RAs. The objective of this consultation and the options within it are therefore unclear to BGE. In our response to the consultation on EY's Review of the CRM, we set out our internal assessment of the reasons why high BM prices do not always coincide with periods of low-capacity margin, namely:

1. **Locational grid constraints dampen units' desire to bid higher than short-run marginal costs (SRMC):** A unit is unlikely to bid higher than its SMRC when it 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[1]. There is thus no need or incentive for the unit to submit simple bids above SRMC.

2. **Having a centrally dispatched system mitigates to potential for ASP to be hit naturally**: The TSO scheduling and dispatch approach will not allow clear definitions of energy-based scarcity and this makes price incentives ineffective. In a centrally dispatched system, the TSO takes actions to solve whole system (energy and constraint) issues and so the BM price is not based on energy-only actions. Where the TSO gives sufficient notice time of a possible event, the system will not get to a point where ASP will be triggered. The TSO have an incentive to give sufficient notice as (i) the SEM is a centrally dispatched system where there is a zero cost to the TSO for taking early actions and (ii) per its TSO Licence conditions has an obligation to maintain system security. This means that the TSO will take early actions to call on available units to maximise their availability well before the point at which ASP is triggered. In contrast,

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

units in GB and Belgium can access these prices naturally through self-scheduling which, in times of scarcity, may allow for ASP to be triggered naturally. This means that comparing the objectives and functioning of ASP in these markets is not useful and such analysis should not be used to inform decisions on ASP in the SEM.

3. **The probability of ASP being triggered is minimised by the high level of participation in the CRM:** The level of participation in the CRM is high due to (i) the requirement for all existing dispatchable units with at least 10 MW capacity to bid into the CRM and (ii) the eligibility of new units to bid into the CRM depends on them being credibly available by the delivery year. This means that almost all units in the SEM already have a strong availability incentive by virtue of their Reliability Option obligation. The adequacy issue is solved by high participation in the CRM before scarcity can be triggered in the BM.

4. **Units already have an obligation to bid into the BM under the Trading and Settlement Code:** If a unit does not bid into the BM, and is not scheduled in another market, it risks exposure to BM prices regardless of the level of those prices. When an RO-contracted unit does not get its volumes fully scheduled at the day ahead market 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 (i) earn any high price that might outturn with a view to being able to cover any arising RO paybacks, and (ii) comply with grid code requirements (failing which the risk is a breach of Licence). This means these units have an incentive to maximise revenue by bidding in all their remaining available volumes when BM prices go high during scarcity events. The early BM price signal incentivises a response to scarcity before ASP materialises because these units know they can achieve higher prices and so will make themselves available.

5. **The impact of the options outlined in the consultation are resultant of forecast alerts, not outturn system events:** The alerts used in the analysis provided in the consultation paper are forecast alerts and are not reflective of the system genuinely being in an amber state for the full duration of those events. Therefore, these events can be seen as the maximum potential for units to earn ASP. If ASP had been triggered for the entire duration of the event in each example, a unit would still only have a small amount of MWs available in the BM to earn ASP. Furthermore, this minimal return is not guaranteed because the TSO still must decide (i) whether the unit gets dispatched, and if so (ii) at what volume. The analysis provided in the consultation paper shows that potential revenue to be earned via ASP is inconsequential from a business case perspective and therefore altering ASP to arbitrarily create scarcity in the market will be ineffective in providing an additional investment signal for availability.

We do not support the implementation of any of the options put forward in the consultation as they (i) are based solely on forecasted value (ii) do not reflect the reality of the market or the system (iii) add complexity to the definition of ASP, and (iv) do not align with the objectives of the SEM[2] or European Balancing Guidelines ("EGBL")[3]. Instead of altering the ASP, BGE proposes alternative ways to address the RAs' availability concerns. Given that 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, we suggest that (in response to Question 2):

1. 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.
2. The concept of non-marginal flagging (NMF) is a legacy from the old SEM days and needs to be removed.
3. The RAs should focus on taking measures that specifically target units with poor availability rather than taking broad measures that penalise units with existing high availability
4. As an interim solution for this winter, we propose an obligation for the TSO to take steps to trigger ASP before the TSO is permitted to dispatch Temporary Emergency Generation ("TEG").

We set out our response to the questions asked in the consultation below.

[2] To operate as one market across two jurisdictions
[3] To have an energy-only Balancing Market stack

1. The SEM Committee has proposed three options for altering the existing trigger for RSP. Please state if you have a preference between these three options, providing reasons for your preference.

BGE does not support the implementation of any of the options outlined in the consultation paper. Each option aims to alter ASP such that it can be aligned with past system alerts. This is not a realistic approach to achieving the RAs' desire to allow scarcity to be reflected in the market price. This is because the system alerts used in developing the options were almost all caused and/ or affected by constraint issues, rather than being a direct result of pure energy scarcity. This means that rather than aligning scarcity with system alerts, these options arbitrarily align scarcity with system constraints.

The options fail to consider 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 an arbitrary BM signal. This heightens investment risk more so than creating increased availability signals. With Renewable Energy Source generation ("RES") increasingly displacing thermal capacity at pace, units (often ageing, cycling plant in need of upgrade) that would have been designed to run mainly baseload are now running more mid-merit/ peak[4]. 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 rollout of RES. Adding another layer of risk via arbitrarily aligning ASP to past scarcity events 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.

Furthermore, the options do not protect units against the ongoing practice of SO-SO trade decisions being taken hours before an amber alert situation occurs. Such SO-SO decisions, while not influencing the BM price, could in practice increase risk by negating the need for a 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 their own. This heightens investment risk with no corresponding tangible investment signal.

BGE has particular concerns regarding the rationale for Options 2a and 2b. We believe these should not be considered in any form for implementation in the SEM, either as standalone measures or coupled with Option 1. Options 2a and 2b are system actions and would lead to more non-energy actions feeding into the BM pricing stack at a time when the RAs should be focusing on achieving a pure energy-only BM pricing stack per the SEM design and EBGL. These options would create locational signals while maintaining uniform pricing. This is wholly inconsistent with the principle function of the SEM to operate as one market. Should the RAs decide to progress with one of these options, BGE believes that only Option 1 should be considered and only on the basis that it is amended to account for the contribution of Interruptible Load. We have set out our specific concerns in relation to each option below.

Option 1

This Option should not be considered for implementation in its current form. It is inappropriate to exclude short-term reserves from the calculation of ASP. The objective of ASP is to respond to scarcity via the BM, therefore Option 1 is inappropriate on (i) a fundamental level as it excludes the contribution of short-term reserves to a short-term market, and (ii) an operational level as the TSO calls on reserves as a last resort before load-shedding, regardless of whether they are long- or short-term reserves i.e., what is important is that all sources of reserves, however small, must be considered before load shedding occurs.

Should the RAs decide to progress this option, it must necessarily be amended to reflect the contribution that Interruptible Load (batteries and DSUs) can make to reserves and short-term scarcity, however small that may be. This is especially important given that this contribution is expected to grow as more

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

long-duration batteries come onto the system. BGE suggests that rather than excluding the contribution of Interruptible Load, there is merit to considering the application of a scalar to Interruptible Load to reflect the duration of its reserves i.e., a sliding scalar that would delineate to reflect the short-term nature of these reserves while not discounting them altogether. This amendment would have the advantage of allowing longer duration batteries a more advantageous scalar such that it would increase towards 100% to reflect the capability of longer duration batteries - while accounting for the inability of short duration batteries - to respond to prologued system events. In addition, this option would exclude batteries from the calculation of ASP thereby undermining their investment case by cutting off an entire revenue stream. Reserves currently provide the only source of back-up revenue for batteries should they fail to secure a position in the market. It is critical that as the level of batteries on the system and the average duration of the battery fleet increases, the contribution of batteries to security of supply is accounted for.

Option 2a

This Option results in creating a market that has locational signals with uniform pricing. The system should not be operated to maintain jurisdictional reserve as this goes against (i) the principle objective of the SEM to function as one market on an all-island basis, and (ii) ASP being an all-island signal. It is not appropriate to treat NI effectively as an islanded node which can secure itself. It is also not reasonable to unfairly penalise units on a system-wide basis, via BM payments, due to a local constraint in one location which is outside of their control. For example, under this option the impact of one large unit tripping or going offline in NI would result in several ASP events leaving the whole island exposed to BM costs due to a local constraint. This option would put the system in a position where only units in NI can be actioned to provide reserves in response to shortages in NI, thereby increasing the all-island price. The BM pricing stack should be all-island, and it would be unreasonable to choose more expensive units in the NI if there are cheaper units available in ROI to cover reserves. This would drive up Dispatch Balancing Costs ("DBCs") on an all-island basis via an increase in constraints which are ultimately paid for by the consumer through Imperfections Charges. The consultation has also not considered the additional risk of emergency flows that can be triggered on Moyle and the impact that this would have on the market price.

Option 2b

This option should not be implemented in the SEM. BGE is of the view that there is no sound basis for applying an arbitrary multiplier to the Operating Reserve Requirement quantity (qORR) such that it helps ensure qSTR meets 100% of LSI across the system. This approach only serves to reflect the size of the LSI which remains mostly static. The approach does not consider other important variables such as seasonality which affects the system's ability to move reserves[5]. For example, for the multiplier's desired effect to remain consistent throughout the year, it would have to be lower in winter to reflect that the expected unavailability of reserves due to constraints is lower because line ratings are higher. There is a lack of consideration as to how this option would work to achieve the desired outcome in practice and in a way that is transparent to the market.

2. Respondents are invited to provide any other views they hold regarding the contents of this consultation paper, including any alternative proposal for the modification of the ASP mechanism that has not been set out in this paper. If proposing an alternative approach, please clearly set out the rationale and explain why it would be preferable to either of the proposed options.

Instead of arbitrarily altering the ASP to align with past scarcity events, BGE proposes alternative ways to address the RAs' availability concerns. Given that 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 the following measures:

[5] Seasonal line ratings affect the availability of reserves as during winter (when we most need reserves) the majority of lines have higher line ratings and higher overload ratings which allow for a greater movement of power and thus reserves from one location to another.

1. **An energy-only pricing stack should be pursued in the near term <u>on an enduring basis</u> 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 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.[6] 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.

2. **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.

3. **The RAs should focus on taking measures that specifically target units with poor availability rather than taking broad measures that penalise units with existing high availability**

The TSO's Review of data for calendar year 2022 found that (i) declared Availability is in the high percentile of Registered Capacity for generators and (ii) declared Availability is in the low percentile of DSU MW Capacity[7]. The EY Review of the CRM noted that the SO is reliant on DSU self-declaration of demand reduction delivered with limited and non-transparent scrutiny of declared reductions ex-post. The TSO's "Review of data for calendar year 2022 found for Generator its declared Availability is in the high percentile of its Registered Capacity and for DSU declared Availability is in the low percentile of its DSU MW Capacity". The TSO noted this was one of the factors that may limit confidence in the reliability of the contribution that DSUs make to generation adequacy. Furthermore, the TSO is incentivised to give dispatchable units, including DSUs, as much notice as possible to be available when required as there is a zero cost to the TSO for taking early actions. This means that DSUs can under-declare their availability during normal system operations and can easily increase their availability well before a system event to cover their RO. There is no downside to DSUs in this respect as they do not have to be available on a continual basis up to their capacity contract level. This points to the need

[6] 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 leads to overall lower BM costs for consumers
- Increased BM pricing transparency and enables 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

[7] Microsoft Word - OSC Consultation Paper for Tariff Year 2023-2024 (eirgridgroup.com) [Section 4.4]

for the RAs to take measures that incentivise DSU availability rather than taking measures which penalise units that already have high availability.

4. An Interim solution for implementation this winter - scarcity events with TEG scheduling

Recognising that it may take time to implement our enduring solution, we outline in this section an interim solution which may provide an additional signal to the market, specifically for demand side response and battery units in the market. The intent is that this solution could be implemented immediately.

The purpose of ASP should be to provide a pure energy signal to the market when there is a security of supply risk relating to an energy shortfall i.e., not a constraint issue. We propose an obligation for the TSO to take steps to trigger ASP before the TSO is permitted to dispatch TEG[8]. TEG capacity will only be brought online when existing, market-based generation capacity has failed or is imminently likely to fail to meet the system requirements[9]. Given the probability of TEG being needed this winter, under this option a signal will be provided to the market to make all capacity available via market dynamics before TEG is called upon. This option also accounts for TSO decision-making in triggering scarcity pricing and therefore minimises the effect of TSO discretion on in-market units during a security of supply event. This is a more transparent alternative to the options outlined in the consultation paper because it:

i. avoids having to define what scarcity means as ASP would be triggered based on a pure energy shortfall;
ii. allows batteries to access the ASP by providing reserves, thereby maintaining a backup revenue stream for batteries should they fail to secure a position in the market;
iii. allows ASP to more transparently and more predictably fulfil its objective of providing strong signals to make plant available at times when capacity is scarce prior to load shedding[10]; and
iv. lessens the complexity of decision-making for participants and TSO during a scarcity event.

BGE would welcome a call with the RAs to discuss in further detail our view as to (i) why scarcity is not being reflected in BM prices and (ii) the alternative interim and enduring measures that can be taken to address the RAs' availability concerns.

I hope you find the above comments and suggestions helpful. If you have any queries thereon please do not hesitate to contact me.

Yours sincerely,

Niamh Trant
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{By email}

[8] CRU2022985 outlines that the operation of all temporary emergency generation will be in compliance with Article 16(2) of Regulation 941 of 2019 on Risk Preparedness in the Electricity Sector which states: "*Non-market-based measures shall be activated in an electricity crisis only as a last resort if all options provided by the market have been exhausted or where it is evident that market-based measures alone are not sufficient to prevent a further deterioration of the electricity supply situation. Non-market-based measures shall not unduly distort competition and the effective functioning of the internal electricity market. They shall be necessary, proportionate, non-discriminatory and temporary.*"

[10] SEM-15-103 CRM Decision 1_0.pdf (semcommittee.com)