Mary O'Kane
Commission for Energy Regulation
Queens House
14 Queen Street
Belfast
BT1 6ED

Thomas Quinn
Utility Regulator
The Exchange
Belgard Square North
Dublin 24

21st December 2016

Dear Mary and Thomas,

Indaver Ireland Ltd currently owns and operates a small, centrally dispatched hybrid renewable generator (17MW registered capacity) in Duleek, Co. Meath. Within the next 5 years we plan to develop two similar generators in Cork and Belfast. Given the timelines, these facilities could become the first new build/own/operate projects in the I-SEM.

Indaver Ireland therefore welcomes the opportunity to respond to the SEM Committee Capacity Remuneration Mechanism Parameters Consultation Paper (SEM-16-073) from the perspective of both an operating plant and a potential new entrant.

Our response covers three thematic areas:

- **We seek a prudent set of parameters that will minimise volatility, particularly in the transitional years of the CRM.** In the absence of any experience with I-SEM scheduling or pricing in the energy market, or the liquidity of secondary trading in the capacity market, aggressive tuning of parameters, e.g. weekly stop-loss limits while keeping the limit at 75% of annual capacity revenue, ASP quickly deviating from the RO Strike price, introduces higher potential ranges in risk valuation and therefore more unpredictable competitive bidding behaviour in the RO auction.

- **It should be explicit in the decision paper which parameters are not intended to change in general, are not intended to change within a long-term contract, or which may be reviewed annually and changed accordingly**. This is important for new entrants.
  - While not within the scope of this consultation, Indaver will draw the SEM Committee's attention to the annual capacity payment exchange rate utilised in the auctions. **This places new entrants with long-term contracts in Northern Ireland with an exchange rate risk on the capacity clearing price (in euro) spanning several years**. It is arguable whether such long-term exchange rate risk is within the spirit of fair competition North and South within the I-SEM. This also could

have an implication for the calculation of Net CONE, and the auction price cap.

- The setting of Price Caps (both for the Auction and Existing Capacity) while capturing new interactions within the I-SEM of a BNE's revenue stream, over-simplifies the complexity of a) difference payments, b) ancillary services under DS3, and c) the potential imposition of bidding codes of practice in the balancing market. **While we agree with the high-level approach of setting the BNE, we believe that the complexity of reasonably estimating I-SEM IMR and ancillary services revenues will lead to material inaccuracies, and this should allow for higher percentages of BNE costs to set the Price Caps than those proposed, at least for the transition period, i.e. to 75% of BNE for existing capacity and to 200% of Net CONE for new capacity.**

Yours sincerely,

Catherine Joyce-O'Caollai
Indaver Ireland Limited

<u>The ASP Function (Section 2)</u>

The paper deals with the formation of the ASP function during the transitional years (May 2018 – September 2021). The T-4 auction for October 2021 will probably be run some time in 2018. For a new entrant, details of the partial ASP Function for the enduring regime are not being consulted on. As a potential new entrant developer, **Indaver requests a firm auction and consultation timeframe** to give certainty around the proposed shape/value of the ASP function for new entrants and the timing of the CRM auctions.

We would also like confirmation that a new entrant generator which delivers within a transitional capacity year will be eligible for a long-term contract.

We would like clarification that the shape of the Partial ASP function is not intended to change from year-to-year, i.e. what is meant that the curve will be "static"?

We have a preference for Option 1, the simple linear increase in ASP, as we believe it comes closest to the spirit of having the ASP start at the Reliability Option strike price. In the context of the market's uncertain reaction to intervening transitional CRM auctions, it also provides for a less aggressive signal to the market.

Under Option 2, the LoLP x VoLL approximation, some of the effect of the SEM Committee's previous decision that ASP will start at the Reliability Option Strike Price is undermined as the ASP jumps to almost four times that strike price with the loss of one further MW of reserve. It appears too volatile to generators offering capacity for a delivery year four years in the future when there has been no pragmatic operation of the market or completed auctions run for intervening years.

To that end, we also have a question regarding the SEM T&SC definition of qSTR. In the I-SEM T&SC under consultation, the qSTR is defined as coming from the "most recent Indicative Operations Schedule" which is turn is defined through the Grid Code, which are proposed to be updated regularly in the I-SEM. Our simple question is whether the reserves indicated on the x-axis in Figure 3 is the same conceptual quantity as qSTR in Figure 4, i.e. the available 1-hour reserves from the most recent Indicative Operations Schedule. Intuitively there appears to be a mismatch between the probability of lost load within an hour (within Figure 4) and a statement that at 600MW of operating reserve there is a greater than 55% chance of lost load (Figure 3).

<u>The Strike Price Formula: DSU Floor Price, Choice of Indices, Carbon Content, Transport Adders (Section 4)</u>

Overall, the Strike Price Formula is more critical for an existing reliable plant and a new entrant than the ASP function. The Strike Price Formula changes the nature and timing of the energy hedges into which a generator may enter (excluding any forward contracting obligations that may also be placed on a generator / company through the Forwards and Liquidity workstream).

Many of the parameters that define the Strike Price Formula will not become known until much closer to the transitional auctions, dependent as they are on the choice of the published reference fuel price index. The cost implications of publishing such a reference fuel index price appears to be causing issues with its selection, and this is of concern because it could potentially result in the chosen index changing year-to-year.

Overall, and consistent with earlier queries above, we would like to know the extent to which the decision made in relation to the Strike Price Formula will be "static", and whether new entrant generators with long-term CRM contracts (who also may have long-term energy hedges) will be protected from any such potential changes.

Indaver has no other comments with the proposal in this section, or on Section 3.

Stop-Loss Limits (Section 4)

The original intent behind CRM Decision 2 would be that a stop-loss limit would be defined over a month billing period, as that is the capacity billing period within the SEM and was under discussion within the Rules Working Group (RWG) at the time. Now Capacity Billing for a generator is effectively split over monthly (for payments) and weekly (for difference payments) cycles following discussion and agreement at the RWG.

Indaver's issue with defining the Stop-Loss Limit as weekly, is that if there is limited liquidity in the Secondary Trading for capacity, a single two-week outage period could result – with unfortunate timing – a penalty applying for otherwise fully reliable participation in the CRM. Secondary trading of capacity has no "market maker" obligation, and without any actual experience of the CRM market (or the I-SEM more generally), having the Stop-Loss Limits at a weekly level appears overly aggressive and a retrospective interpretation of previous SEM Committee decisions.

Indaver therefore suggests a weekly Billing Period Stop-Loss Limit at 0.25 x Annual Capacity Fee, roughly one quarter of the previous "Billing Period" fee of 0.75 x Annual Stop Loss Limit (which is 1.5 times the annual fee) when it was framed in terms of "monthly"[1] stop-loss limits.

Termination Fees (Section 5)

Indaver agrees with the concept of termination fees. Nevertheless, we are not convinced that there is a linear relationship on the size of the failed delivery of capacity to the impact on the consumer, i.e. the failure of a 200MW plant to deliver will have a greater-than-pro-rata-to-MW-size consequence to consumers than a 20MW facility failing to deliver. We believe that there should be non-linear increasing progressive scale of penalty with increased size of generation project, subject to our belief above being confirmed by TSO analysis.
We also agree with the time-weighted nature of the penalty, with penalties increasing for failure to deliver the closer to delivery one gets. Given, however, the potential for our plant to deliver by 2020, the financial implication of the ruleset proposed in the

[1] See for example 5.4.3 for a reference to "monthly stop-loss" limits.

consultation paper are unclear to us, as of the time of writing this response, we do not know when the transitional auctions will be run[2].

We also request the SEM Committee to check with the jurisdictional policy of the CER and UR to ensure that there is not double counting of bonding arrangements for new connections to the transmission or distribution systems, i.e. that the cost to the consumer of planned-but-not-delivered capacity is counted only once across all bonding arrangements.

Existing Plant Termination Fees (Section 5)

We believe that Termination Fees for existing plant are unnecessary, and probably unenforceable in several circumstances should a generator become insolvent and cease to trade.

We have no comment on the specific other circumstances cited, which include minor investment below the financial threshold, new/unproven DSUs, and other capacity providers which have not demonstrated ability to deliver.

Performance Bonds (Section 5)

Performance bonds are sufficient at €10/kW to prevent spurious bids into the capacity mechanism in the first place, and should be drawable if a new entrant does not increase the level of required bonding at the specific required time. Any other approach requires projects to fund €30/kW of a bond for several years (the difference between the €10/kW and €40/kW) which is not commensurate with the balance set out by the SEM Committee in their preferred option.

Auction Cap (Section 6)

The Auction Cap needs to work within the context of the new pricing arrangements, and also whether the proposed balancing offer regulations are in effect or not for the calculation of IMR (SEM-16-059). Furthermore, the adjustments for ancillary services in line with the overall DS3 budget also assumes no new entry or increased capability from existing providers and no performance penalties for the BNE. There are also interactions between DS3 and the IMR if a commitment model is to be utilised under DS3. All these overlooked factors would suggest that the existing methodologies for calculating IMR and DS3 revenues will not be fit for purpose, and are complicated – if not possible – to accurately ascertain at this time. Therefore, a higher percentage of BNE price for the auction cap is recommended, e.g. 200% of the BNE price.

Existing Capacity Price Cap (Section 6)

The paper acknowledges that the Existing Capacity Price Cap includes Expected Reliability Option difference payments. With the suggested price cap set at 0.5 x Net Cone (€, once the system reaches 16 hours at full ASP ((€3000/MWh - €500/MWh) x 16 hours * 1000 = €40k/kW), existing generators are reliant on new entrants to have raised the price above that offer cap as otherwise the CRM will be a loss leader for existing reliable generation, i.e. they will be foregoing more inframarginal rent through

[2] See 2.4.4. of SEM-16-039.

difference payments than the revenues paid by the capacity mechanism . This needs further consideration in how the offer cap is calculated for any given year. As above, we believe that the Existing Capacity Price Cap should be set at 75% x Net CONE (howsoever calculated) until all the aforementioned interactions are fully understood.

Demand Curve (Section 6)

In line with our previous comments, we want to see a predictable capacity price, particularly during the transitional period, without volatile jumps or falls in revenue. To that end, typical new entry with the potential impact of any new entry (or exit) on capacity market prices relative to the price-sensitive range of the demand curve, we prefer to see a simple demand curve with a zero crossing at 120% of the capacity requirement (Curve A).

Load Following Parameters (Section 7)

It is difficult to comment on this section without being provided information regarding the Secondary Capacity Products that will be allowed in the auction. The day/night/peak differentiation of FPFCQSF might be irrelevant if day/night/peak products are not offered, i.e. the day (or peak, if relevant) FPFCQSF would dominate the allowable offer to deliver secondary capacity for a calendar day.

In the round, it seems prudent to maintain this level of granularity not to restrict the forms of secondary capacity product possible to allow for differential in trading of day/night maintenance schedules.