EPUKI Response to Best New Entrant Cost of New Entry (BNE – Net CONE) Consultation

EPUKI has significant concerns related to this consultation and the information published alongside it. The CEPA/Ramboll report which was commissioned by the RAs to support this consultation is inadequate in its level of detail which make any conclusions drawn from this analysis inaccurate and unreliable. It difficult to respond constructively to information that is based on forecasts which are incorrect. As such, we request that the SEMC re-forecast the Net CONE and publish an updated consultation based on more accurate information and more detailed analysis.

More generally, we are concerned by the overall direction of travel suggested by this consultation paper. The position in the consultation paper suggests a substantial reduction to BNE Net CONE which will subsequently reduce the Auction Price Cap. It is difficult to understand how the SEMC can support a position which would reduce the price cap given the current Security of Supply concerns which are expected to last until the end of this decade.

In recent years, the Capacity Market Mechanism (CRM) has proven ineffective in delivering much needed capacity to the SEM. Eight of the nine gas units which were awarded contracts in the T-4 auctions in 22-23,23-24 and 24-25 for Ireland have terminated prior to completion w. Additionally, a number of existing New Capacity projects, which secured contracts through the T-3 and T-4 (2024/2025 and 2025/2026 respectively) Capacity Auctions, are facing significant costs increases and delays resulting from third-party actions. This comes at a time when Ireland is facing an increasing likelihood of blackouts in the coming winters and EirGrid have identified huge deficits in the level of installed generation capacity. If the SEMC were to reduce the Auction Price Cap, the result would be to further exacerbate the Security of Supply situation in SEM. If the Net CONE is not set at a level which accurately reflects the costs faced by a unit, it will not be possible to secure New Capacity through the CRM. We therefore request that the SEMC recalculate the Net CONE is recalculated in time for the next Capacity Auction, addressing all of the issues identified below. If it is not possible to recalculate Net CONE in time for the upcoming Capacity Auction, then the timeline for auction should be delayed to facilitate this.

In the long-term we believe that the SEMC should consider a wider review on the BNE process and the importance of including the right mix of technologies in order to deliver the investment which is necessary in Ireland's electricity system.

This paper is damaging to investor confidence at a critical time for the Capacity Market. The publication of this review, just four months ahead of an auction in which participation is mandatory, represents significant regulatory uncertainty. This is compounded by the fact that the SEMC have published a review based on unreliable analysis which appears, in some cases, to defy common sense. Additionally, the NPV implications of the proposals as currently drafted suggests that the delivery of a CCGT would result in a net loss to investors.

As well as delivering New Capacity to ensure Security of Supply, it is important that Existing Capacity has appropriate market signals and opportunities to remain economically feasible. This consultation (as currently drafted), would result in a significant reduction to the Existing Capacity Price Cap (ECPC), delivering an exit signal to existing generation. As well as a recalculation of Net CONE, we request that the SEMC consider an amendment to the current methodology of deriving ECPC. We believe that the ECPC should be calculated by multiplying Net CONE by 0.8, rather than the current rate of 0.5.

In terms of the analysis itself, EPUKI disagrees with a number of the assumptions used by CEPA/Ramboll. The forecasted revenue used in the consultation paper is inaccurate as it does not take account of the increasing portion of renewable energy expected in 2030 and beyond. Additionally, the costs used in the forecasting are inaccurate and do not reflect actual costs being incurred by participants. Some of these issues have been outlined in greater detail below:

Inframarginal Rent

The inframarginal rent (IMR) forecasted by CEPA/Ramboll for CCGT units is unrealistically high. The exact details applied by CEPA/Ramboll in this forecasting remains unclear which makes it difficult to address comprehensively. However, there are two key issues with the figures provided in the analysis. The first is a lack of dedicated modelling in forecasting a baseline IMR for 2026/2027, and the second is an extrapolation of this baseline IMR across the lifetime of the capacity contract.

It is noted that CEPA/Ramboll use a PLEXOS model run to forecast IMR in 2025/2026 and then apply a 2% inflation uplift to obtain an IMR forecast for 2026/2027. Given the importance of the Net CONE in incentivising investment in new generation, we believe it is necessary to carry out dedicated modelling when estimating the baseline IMR. We welcome that CEPA/Ramboll have acknowledged this in the clarifications document and noted that the SEMC is considering undertaking additional runs of modelling for the final Net CONE.

IMR forecasts need to reflect the expected uptake in renewable energy from 2026/27 to 2035/36. The evolution to a low-carbon system represents a significant shift in the energy market and needs to be captured in IMR forecasting. This shift is reflected in government policies in both Ireland and Northern Ireland, both of which target 70% renewable electricity by 2030. Furthermore, EirGrid/SONI's Generation Capacity Statement (published in October 2022) indicates that renewable capacity is set to increase by 168% from 2022-2031.

Additionally, the fact that CEPA/Ramboll have used 2025/2026 as a base year for IMR suggests that the impact of the Celtic Interconnector has not been captured in the forecast. This is a substantial omission as our modelling suggests that the interconnector will have a significant impact on reducing IMR. This needs to be factored into the CEPA/Ramboll forecasts. We also note the potential for further additional interconnection which must also be considered.

EPUKI has carried out its own modelling on forecasted IMR between 2026/27 and 2035/36. This forecasting is based on publicly available information contained within the Generation Capacity Statement and unlike the work carried out by CEPA/Ramboll, models IMR for each year of the ten-year period. The results of this analysis indicate an IMR which is significantly lower than the value presented in the consultation.

This evolution of the power system will likely result in a significant reduction to the IMR available to conventional units in the latter years of a ten-year contract, and this is not reflected in current forecasting. We acknowledge in CEPA/Ramboll's supporting note they have explored the possibility of a glide-path approach which assumes IMR reduces to zero after ten years. We believe that it is imperative to include this assumption in the IMR modelling in order to accurately reflect the impact that renewables will have on the market.

We also note that the SEMC's recent review of the CRM (SEM-22-054) included a number of recommendations which would also reduce a unit's IMR. Notably, any increase to the current security standard, or greater capacity requirements to account for non-delivery would result in a greater volume of thermal generation in the market. The impact of these recommendations should be carefully considered when forecasting IMR post 2026/2027.

Inflation Assumption

In forecasting gross CONE out to 2026/27, CEPA applies an assumed inflation of 2%. CEPA's report notes that this assumption is consistent with the Pöyry report from 2018. While it is noted in the report that higher inflation costs will be captured to some extent in cost of capital parameters it is unclear to what extent they have been included.

In October 2022, the Economic Social and Research Institute (ESRI) forecasted inflation in Ireland to average 8.1% in 2022 and 6.8% in 2023. This represents a significant increase on the inflation applied by CEPA. In the UK inflation rates are forecasted to be even higher. Citi have forecasted that consumer price inflation (CPI) in the UK will peak at 18.6% in January 2023. We believe it is inaccurate to apply a 2% inflation assumption in the short-term, and unclear whether the assumption is accurate in the long-term.

Additionally, while the above figures are based on general inflation, construction-related inflation has been running higher than general inflation across 2022. The producer prices index (PPI) forecasts a 9% inflation in construction-related costs in 2022, with an additional 12% and 4% in 2023 and 2024 respectively. A number of OEMs have indicated to EPUKI that their costs for project delivery have increased by 20-30% in 2022 alone.

This issue may be less relevant pending the outcome of SEM-22-071. If the SEMC decide to approve the modification to include indexation adjustments to the calculation of Capacity Payments, the need for an accurate inflation assumption in setting the Net CONE is reduced. However, if this is not the case, then the inflation assumptions used in CEPA's forecasts must be urgently reviewed.

EPC Costs

EPC contract costs represent the single largest cost element for New Capacity projects, typically making up 75-80% of overall capital costs. This means that setting accurate EPC costs is essential for calculating an accurate Net CONE. In their analysis CEPA/Ramboll present EPC costs which are €14.3m lower than the values calculated in 2018. We believe that these results are inaccurate.

CEPA/Ramboll have used February 2022 as a reference date for forecasting EPC costs which a new generator project is expected to incur. This decision fails to account for the significant inflation and construction cost increases which have occurred since the beginning of the year. These increases have been outlined above and make it impossible to deliver a project in line with the costs used by CEPA/Ramboll in their analysis.

In their analysis, and follow-up clarifications, CEPA/Ramboll have not provided comprehensive detail on the breakdown of EPC costs. This makes it difficult to address specific cost element reductions from the 2018 figure. However, general market trends and EPUKI's experiences in developing projects suggests that such a reduction is unrealistic. Our modelling of EPC costs for a theoretical 200 MW CCGT unit are €20m higher than the figures presented in the consultation. There are additional costs which CEPA/Ramboll have derived based on EPC costs. One example is contingency, which is set at 5% of the EPC costs. This level is too low and not reflective of the actual contingency which an investor will build into new generation projects. It is acknowledged that previous BNE reviews have applied a value of 5%, however the combined impact of high inflation, difficulty in sourcing materials, challenging project timelines, and regulatory uncertainty mean that this 5% value is no longer appropriate. We recommend a 10% rate is applied to more accurately capture the contingency costs which investors will build into projects.

Asset Life

The BNE analysis assumes an asset life of 20 years for a CCGT. This should be reduced to reflect current market conditions, length of the awarded capacity contract and future market signals. These factors, which will determine the investment case for new thermal projects, suggest an asset life of 10 rather than 20 years. In addition, debt finance is only available to projects for a 10-year period which further reflects the market's view on the asset life.

Current policy in both Ireland and Northern Ireland aims to achieve 70% renewable electricity by 2030. In order to deliver this target, it is expected that the role of conventional plant will evolve to be more supportive of intermittent renewable generation. This will likely result in a shift away from CCGT plants towards more flexible OCGT plants. As any contracts secured in the next T-3 Capacity Auction would be for delivery in October 2025, it is unrealistic to assume a CCGT will feasibly operate past 2035 (based on a ten-year capacity contract).

Based on the above, we believe that a ten-year asset life is a more accurate assumption for the Net CONE modelling.

Cost of land

In forecasting the cost of land for development, CEPA have used a value of €17,949 per acre (with a 100% uplift applied for a value of €35,898 per acre). It is noted that this figure is based on data from the Farmer's Journal with an arbitrary uplift applied to reflect the fact that not all agricultural land is suitable for constructing generation plant.

The 2018 BNE study used a value of €150,000 per acre. This represents a reduction of almost 90% in land value between 2018 and 2022. It is noted that the 2018 figure was based on an assessment of the estimated costs of suitable greenfield sites in Ireland and Northern Ireland. This methodology is more detailed and robust than the approach used by CEPA/Ramboll.

Additionally, EPUKI's own experience in assessing the market for appropriate sites indicates a range which is significantly higher than both the 2018 and 2022 figures. Land which is suitable for hosting thermal generation should generally be zoned for industrial use rather than zoned for agricultural use which significantly increases the land cost. in our assessment.

Fixed Recurring Costs

In addition to the above, we have identified a number of issues with the Fixed Recurring Costs included as part of the Net CONE analysis.

CEPA use a fixed value of for electricity transmission charges which is questionable given that these costs change year-on-year. The value applied by CEPA is aligned with the 2021/22 transmission tariffs. However, transmission tariffs in 2021/22 were the lowest in the last five years. This would result in misleadingly low costs over a five-year period. The table below outlines the network capacity charge rates for transmission-connected generators for the past five tariff year periods:

2018/19	2019/20	2020/21	2021/22	2022/23
€2,068.6/MW	€2,164.0/MW	€2,224.0/MW	€1,320.7/MW	€1,704.4/MW

Table 1: Network Capacity Charge for transmission connected generators. CEPA used 2021/22 values.

Unfortunately, it is unclear from CEPA's report how they have calculated the overall transmission charges applicable to a new unit. But it is clear that selecting the 2021/22 value is inappropriate given the rate of network capacity charge rates which a transmission-connected unit will be exposed to. In the most extreme example, the network capacity charge rate in 2020/21 is 68% greater than the rates in 2021/2022. The fact that CEPA have not accounted for any variability in these rates is also questionable. It is also unclear why the 2021/2022 tariff rates were not applied, given that they were publicly available at the time of publication of this consultation paper.

The lack of variability also presents as an issue in CEPA's forecast for gas network charges. Over the past five years these charges have increased by an average of 5% each year. CEPA have used a fixed value for their analysis. The omission of variability represents a lack of robustness to the forecasts, and results in unrealistic values for Net CONE.

To address the above points, we recommend firstly that electricity and gas network charges are set at a rate which reflects an average of the last five tariff years. This will provide a more accurate base figure of Fixed Recurring costs that a unit will incur over its lifetime. Secondly, in order to forecast what these charges will look like in 2026/2027 and beyond, the five-year average tariffs should be increased by an incremental percentage to represent price increases expected over the course of the capacity contract.

Weighted Average Cost of Capital (WACC)

CEPA/Ramboll have applied a market-based approach to forecasting the WACC for a new thermal generation project. This forecasting assumes a Cost of Equity of 8.06% post-tax (8.82% in Northern Ireland). In practice, the Cost of Equity is significantly greater than this in order to secure investment in conventional projects. This is a result of greater risk driven by inflation, challenging timelines, and regulatory uncertainty.

There are a number of contributing factors to regulatory uncertainty within the SEM. One key factor is mixed messaging around the technology types which the SEMC desire to see in the market. The CRU have indicated extensively that significant volumes of flexible gas generation is required to ensure Security of Supply. This messaging was followed by a SEMC direction to apply significant de-rating to OCGT units which are subject to run-hour limits. Until this regulatory uncertainty is addressed, financing costs will be inflated.

DS3 Revenue

The CEPA model assumes that DS3 revenue available to OCGT units will increase from €7.94m from 2022/23 to €8.59m in 2026/27. We believe that this is an unrealistic assumption, and it is much more likely that DS3 revenue will decrease following the transition to the System Services Future Arrangements. The Future Arrangements seek to move the procurement of System Services to a competitive market. It is noted in the CEPA analysis that a 20% reduction factor has been applied to the tariffs to capture the transition to competitive arrangements. However, we believe that a greater reduction is required to more accurately reflect the impact of competition in System Service procurement.

To some extent the impact of competition is already being experienced in the SEM. In August 2021, the TSOs introduced a mechanism to manage System Service expenditure. This measure consisted of a 10% reduction to all tariffs for fast-acting services (FFR, POR, SOR, TOR1, and TOR2) for each 100 MW of fast-acting service provision procured. In September 2022, the TSOs consulted on further reductions to System Service tariffs. This consultation included a range of options to reduce System Service payments including a reduction of up to 35% on System Services tariffs from Q1 2023.This reduction is greater than the 20% applied by CEPA/Ramboll in their modelling and this does not take into account the fact that the System Services Future Arrangements will cap the volume of System Services procured by the TSO, which will reduce DS3 revenue even further.

As with the IMR forecasting, System Services revenues will also be negatively impacted by the result of greater renewable uptake. In order to provide System Services, a unit needs to be running (with the exception of a small number of the longer-term products). Thus, less running time overall will correspond to less System Services revenue which needs to be reflected in the forecasting.

Conclusion

EPUKI has identified a number of significant issues with this consultation and the analysis which supports it. In order to address these key issues, we request that the SEMC reconsult on a new BNE. The new consultation should address the key issues identified above. This review will need to be carried out prior to the next Capacity Auction. EPUKI is supportive of a delay to the Capacity Auction timetable in order to facilitate this review.

Separately, we believe that when the Net CONE is recalculated, the SEMC should amend its approach to setting the ECPC. We recommend that the ECPC be calculated based on 0.8 times the Net CONE, compared to the current rate of 0.5.