SEM-22-076 Best New Entrant Consultation

SSE Response

SSE Thermal

1.0 Introduction

SSE welcomes the opportunity to respond to SEM-22-076 Best New Entrant Consultation. For the avoidance of doubt, this is a non-confidential response.

1.1 Who we are

SSE is the largest renewable energy developer, operator, and owner in Ireland's all-island Integrated Single Electricity Market. Since entering the Irish energy market in 2008, SSE Group has invested significantly to grow its business in Ireland, with a total economic contribution of €3.8bn to the State's economy over the past five years. We have also awarded over €9 million to communities in the past 10 years as part of our community benefit programme.

SSE is building more offshore wind energy than any other company in the world right now. We are currently constructing the world's largest offshore wind energy project, the 3.6 GW Dogger Bank Wind Farm in the North Sea, a joint venture with Equinor and Eni. This is in addition to Scotland's largest and the world's deepest fixed bottom offshore site, the 1.1 GW Seagreen Offshore Wind Farm in the Firth of Forth, a joint venture with TotalEnergies, which reached first power in recent weeks. In the most recent Scotwind process, SSE Renewables was awarded the rights, along with partners Marubeni Corporation (Marubeni) and Copenhagen Infrastructure Partners (CIP), to develop what will become one of the world's largest floating offshore wind farms off the east coast of Scotland.

We plan to bring our world-leading expertise in offshore wind energy to Ireland with plans to deliver over 3 GW of offshore wind energy in Irish waters, starting with our Arklow Bank Wind Park Phase 2 project off the coast of Co. Wicklow.

Through our SSE Thermal business, we continue to provide important flexible power generation. SSE's power station Great Island is Ireland's newest combined cycle gas turbine (CCGT) power station and one of the cleanest and most efficient on the system, generating enough electricity to power half a million homes. The acute need for flexible generation in Ireland has been demonstrated over the last twelve months, with EirGrid's most recent generation capacity statement showing that a shortfall in generation capacity was a significant risk this coming winter and for a number of winters to come, resulting in emergency measures being implemented by the CRU and Government.

While existing power stations continue to play a critical role on the system, SSE view the future of dispatchable thermal generation as being abated thermal, with Carbon Capture and Storage, hydrogen or other low-carbon fuels being the primary options. SSE have over 5 GW of zero and low carbon thermal under active co-development in the UK.

We will continue to evaluate opportunities to bring our expertise and investment in decarbonised flexible generation to Ireland, but it is vital that the state, Regulator and TSO provides an appropriate investment landscape to unlock such developments.

2.0 SSE Response

We have provided a response below under the following themes:

1. Change of BNE prior to T-4
2. CRM reform
3. The BNE analysis
4. BNE for future transition

2.1. Change of BNE prior to T-4

It is noted that the proposed new BNE and accompanying lower price caps are targeted for implementation in time for the T-4 2026/27 auction expected for March 2023. The qualification and exemption window for this auction closed on 6th October 2022. Therefore, investment decisions, business case analysis and modelling have been conducted already prior to any capacity considering a qualification application to this auction. It is inappropriate to be proposing such a significant change to assumptions for the Net CONE and associated price caps for the T-4 2026/27 auction which is due in March 2023. Any such change is highly likely to undermine confidence of market participants, both new and existing, at a time when the Irish system is highly dependent on CRM to support the capacity it needs to keep the lights on as well to procure much needed capacity to plug the capacity shortfall projected up to 2031 by the TSOs[1].

We note the SEMC's reference in the paper that the relationship between APC and the BNE may be re-considered to acknowledge uncertainty. Respectfully, while this may bring in what is needed for today, the BNE and the auction delivery is for a time into the future where conventional generators with no pathway to net zero, are not being signalled by such a minor adjustment to price caps and not to BNE. Furthermore, an assumed increase in APC (potentially 3 versus 1.5) coupled with the degree of drop in the Net CONE being proposed does not produce significantly more value for new entrants[2] and risks an asymmetric approach if it is not accompanied by an adjustment of the level of ECPC (making it higher). Any consideration of price caps must also acknowledge that they will need to reach levels much higher than previously considered given the current level has still been insufficient for delivery and that clearing prices for existing and new have not reflected the current price cap levels[3].

On the subject of capacity delivery, it is also important to consider the realistic potential for entry of a CCGT at the T-4 auction given the lead-time for delivery of the unit is in fact 3.5 years at best, (including planning (and climate for approval of planning of fossil fuel projects), environmental consenting and licensing). Currently, there has been no change in delivery timeframe where the EY review does signal that this needs to change to encourage more delivery rather than risk termination. This appears to be an omission in the analysis.

Even more significantly, existing units which are relied on greatly at this time to keep the lights on given a chronic capacity shortfall risk facing an even lower return on capacity, (with an ECPC being proposed at €29.15/kW/year). Existing units do not have the same ability to opt out of an auction if it proves that the price cap is uneconomic. Existing units targeting the T-4 2026/27 have now timed out of the exemption application window for this auction and therefore, the USPC process as well. As per the paper, existing units are now potentially locked into an extremely low ECPC level. This level erodes revenues that otherwise are needed to cover operating costs and is at a level unlike anything that investors could have predicted, judging from the signals that demonstrate that existing capacity needs to be retained and the risk to security of supply if they unduly exit[4]. There is no consideration in the SEMC paper of a re-evaluation of the ECPC relationship with the BNE and given the timing, no opportunity for adjustments via exception application. As per the EAI response, we would support that if there is an intention to increase the APC (to reflect uncertainty for this T-4 auction), this must be matched with symmetric adjustment of price signal at ECPC, i.e., making it higher.

On the topic of the USPC we have been clear in the past that a bespoke bid process (except by exception) defeats the purpose of a regulated price cap since it undermines that signal and where it is over-subscribed, suggests the set price cap is too low. The USPC is not a used as process by exception, results in a narrow set of costs being accounted for and a separate regulated tariff being set for a project based on RA conclusions on cost. We would align with general views communicated in the Frontier analysis and EY analysis that rigid caps and rigid USPC processes are more hindrance than assistance and that they need to be relaxed.

To reiterate, it is wholly inappropriate to be changing the goalposts for an auction that is so near, from the perspective of investor decision-making, modelling and corporate approval. As qualification applications have already been made, any such rule-change is effectively retrospective and entirely unavoidable (particularly for existing units). SSE believes this degree of regulatory uncertainty will seriously undermine confidence in the CRM and in the regulation of the electricity market in Ireland.

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[1] EirGrid and SONI Generation Capacity Statements 2022

[2] Assuming a multiplier of 3, an APC cap of €174.93 with the modelled flat rate of inflation, as compared to the recently readjusted APC (SEM-21-110) of €146.92/kW derated/year to reflect inflation increases.

[3] As per the Frontier Economics analysis and the EY review of the market—clearing prices have not reflected price caps and despite comparative price cap levels to those being proposed, approximately 600MW of capacity has been terminated between 2018 and auctions for 2024/25.

[4] DECC Policy Statement on Security of Supply; Security of Supply: Generator Financial Reporting Obligations - Commission for Regulation of Utilities (cru.ie); Dublin Security of Supply: Measures to mitigate the risk of disorderly exit - Commission for Regulation of Utilities (cru.ie);

With the benefit of more time than has been provided, it would still have been our preference that a more significant review of the BNE had been consulted on to reflect the changing landscape and acknowledging that the BNE needs to encourage tomorrow's energy mix. Failing that, we are aligned with the EAI that the underpinning assumptions do not articulate accurately the true values and considerations of a rational investor, and interim adjustments should be made to the BNE for T-4 2026/27. However, following March 2023 there must be a holistic review of the Net CONE mechanism. This view is consistent with previous EAI messaging signalling industry's expectation that the BNE would be more broadly reflective of EU obligations and changing ambitions such as those signalled under Clean Energy Package.

Solution: The process for the T-4 has already commenced with qualification. Therefore, the assumptions underpinning the BNE should not be fundamentally shifted for this auction. The CEPA/Ramboll analysis suffers from underestimated assumptions which could be updated. As per CEPA/Ramboll IMR assumptions for instance, if the more cautious approach were adopted, or year-on-year analysis was conducted, this will likely arrive at a different reference unit. This interim approach would simply preserve the investment signals for the forthcoming auction in acknowledgement that the auction process has already commenced, and otherwise there is a risk of units not qualifying or participating at auction. Uncertainty is definitely of concern and therefore re-evaluation upwards of both APC and ECPC would also be necessary. The SEMC should then take time to review the BNE more holistically after March 2023 (with the benefit of the CRM review and responses) and seek to design the Net CONE to support the dual objectives of security of supply and changing landscape which is moving towards low carbon/net zero in line with Government and EU policy and legislation.

2.2. CRM Reform

The methodology underpinning the CRM framework has failed to deliver the capacity needed for the country, because of certain identified shortcomings. We have commented on the separate CRM review and would agree with some of the proposed recommendations for reform. However, the Best New Entrant and the impact this has on investor entry and exit was not fully considered and is an un-analysed shortcoming of CRM design. Had investors been consulted during the CRM review, this could have been included as a valid area for review. We note the mention of application of bidding restrictions only by exception (in the CRM review) since the current format is seen as specifically interventionist and increasing the risk on existing units to be able to recover their ongoing fixed costs. We would support that view.

It is our view that whatever improvements could be made to the CRM including for instance, relaxing or removal of price caps, a stronger focus on capex recovery only, would allow for price discovery, mitigate market power in other ways and specifically would readdress value of existing units where there is substantial redevelopment potential at older and more attractively sited existing locations. The SEMC's focus on increasing APC only fails to acknowledge that retention of the most attractive sites on the system (i.e., where existing and sometimes aged units are located) will be in fact amongst the most cost-effective re-development opportunities in the future, both because of their location usually close to demand centres, as well as the cost savings associated with already developed networks, connections, and sites as brown field.

The effect of the proposed BNE, especially if there is an increase in the APC price cap multiplier alone, is that new entry is only important in the period in which it enters the market. Thereafter, the focus will be on forcefully de-valuing the cost of existing units in order to present a cost minimisation approach. Investors handle far longer time horizons than simply the delivery of a project. A CCGT life expectancy is ~30 years and for all that time, investors will be concerned with making and recovering investment as well as future returns. Therefore, the ECPC (representing value of retained capacity in the market), is as important to a long-term investor in new or existing capacity, as the APC. Furthermore, it is key for the SEMC to understand that new entrants will assess the health of a market not only based on what they can earn, but what their existing competitors **are earning**.

Market landscape and price caps currently demonstrate to investors a highly risky market to enter with continued depressed price caps and no other mechanisms are being instituted to better tackle market power, without increasing investor risk or uncertainty:

- that there is in effect a regulated tariff in place which does not allow for repowering, redevelopment of existing sites (since USPC is a non-transparent process that also ends with a regulator-determined bid price based on a narrow set of approved costs, and current APC does not reference a suitable technology for net zero),

- the NCIRT mechanism is not sufficiently flexible for conversion, repowering or redevelopment and needs review,
- that value of existing units drops after the 10-year contract time (despite the projected 20-year horizon for CCGTs in the CEPA paper and 30-year lifetime of the equipment). It is well-known that other countries provide longer term capacity contracts and that a longer time horizon logically reduces investor risk (which otherwise is priced in based on shorter timeframes for guaranteed return),
- access and dispatch are uncertain (firm access, certainty of being in merit, running regime, grid connection, reinforcement delivery). With a central dispatch system running regime and dispatch certainty lie with the TSO and the risk is outside the control of the generator to mitigate or forecast accurately,
- exit is locked in at three-years advance notice[5] and in fact there is an issue with capacity security such that generators face compliance declarations confirming financeability[6],
- system service revenue is uncertain (yet to be determined)[7] and therefore cannot be estimated by a rational investor at this time and any forecasts of revenue cannot be verified at present, and
- IMR has been underestimated and is used as an offset to justify lower Net CONE values (as proposed in this consultation with respect to CCGT higher IMR returns).

It is our view that the current framework is being approached in a rigidly cost minimisation fashion and applying rigid price caps and bespoke bids in a regulated tariff manner, whilst signalling that this is a market mechanism. This approach must be fundamentally reformed if it is to respond to the changes in investor priorities into 2030 (which includes strong signals in financing towards decarbonisation, low carbon and net zero investments). The original rationale for the CRM was to **incentivise** new capacity and procure this capacity to deliver local resilience and security of supply, since the market alone could not manage to signal sufficient new investment. The resulting CRM market and approach to BNE that market participants participate in is currently all downside with a relatively short-term upside (bearing in mind the lifetime of the equipment), and no mechanism for projects to exit easily when revenues are no longer economic (three-year closure notice and low ECPC multiplier). Therefore, the new BNE is creating a risk of default.

ACER calculation methodology

In reviewing the BNE consultation we have taken the time to review the ACER requirements regarding the calculation of the Best Net Entrant Net CONE[8]. The decisions made by a rational investor are not fully expressed in the SEMC approach to Net CONE which would include amongst other factors outlined in this response, the rate of return on their project investment, and the economically sustainable operation of their assets during its lifetime. Furthermore, certain modelling approaches in the analysis such as use of a one capacity year extrapolation to predict future revenues and costs, is nowhere recommended in the ACER requirements. We would rather argue, as below, that the provisions under ACER 23/2020 are not fully realised in the proposed Net CONE and BNE calculation.

Net CONE consideration of uncertainty and diversity (article 9, 10, 15 &16)

Articles 9 and 10 relate to the calculation of Net CONE for each reference technology, for every year across a given timeframe and including calculation of both a fixed and variable Net CONE (further elaborated in Articles 15 & 16) for each reference technology. The fixed cost of entry or renewal/prolongation in the definitions also provide the only signal in the calculation where expected revenues are in fact mentioned, with no limitations. It is also telling that there is a separate interpretation of the revenues (and therefore costs) associated with new entry as well as prolonging or renewal of existing plant. None of the underpinning analysis for the proposed BNE Net CONE suggests any awareness of these elements of the calculation, most specifically the potential of existing units and provisions for their future optimisation since they are ensuring the lights remain on.

[5] Grid Code (eirgridgroup.com)

[6] Security of Supply: Generator Financial Reporting Obligations - Commission for Regulation of Utilities (cru.ie)

[7] As per a recent System Services workshop held by the Regulatory Authorities, it appears clarity in system services will unlikely be delivered before 2026, which affects existing investment decisions for the T-4 2026/27—therefore modelling assumptions are estimating what cannot be readily estimated by a rational investor at this time.

[8] Microsoft Word - VOLL CONE RS - Annex I (europa.eu)

There is also a provision in the requirements under Article 9 to account for uncertainty by applying a different value for each year of the given timeframe to account for specific developments in economic and technical parameters. Responses from CEPA regarding IMR being overly optimistic, RES penetration and other relevant unknowns like hydrogen conversion and how this impacts the BNE—could have been accounted for with such provisions. The EAI response and Frontier analysis provides further detail on this point, but we agree that the BNE proposed does not align with the full intent and options outlined in the ACER methodology.

Reference technology (article 10)

Reference technology is very specifically worded in Article 10 as the type of technology in which investment decisions will be made by a rational investor. This centres on the importance of the Net CONE to accurately model and predict the technologies that investors are most likely to invest in. We support the need for a Net CONE to continue to be set.

Article 10 continues to outline that the intent is for reference technology to reflect the type of technology that is standard, has the potential for entry and would not be hampered by any European framework. As demonstrated in the CRM review analysis, no CCGTs have entered the market in the period analysed. The likelihood of large volumes of CCGTs entering the market is equally low. There is strong national and regulatory pressure against such technologies entering the market (as signalled by the EPA, targets under Climate Action Plan and amending legislation, planning rejections and financing landscape). We would also consider the spirit of the Clean Energy Package would also concur with this concerted regulatory pressure against such technology entering the market in that future period unless it is carbon abated in some manner since it would be delivering in 2026/27, a mere four years from meeting of 2030 targets. Therefore, the standard approach to reference technology is not accurately justifying that these are the technologies that a rational investor would in fact seek to deliver.

SSE ourselves are clear in our corporate statements around development of unabated carbon projects and our commitments to net zero, which are backed by our shareholders. This focus from a large energy player in the SEM supports the fact that the approach to reference technologies for this BNE does not reflect the investments that a rational investor will make in 2026/27 and for the period that the BNE will apply out to 2030, (assuming in remains in place for the same period as the existing BNE). Our corporate view is also by no means unique in considering that future investments will lie in net zero, decarbonised investments.

Accounting for environmental requirements (article 11)

Article 11 is clear that environmental requirements and costs of environmental compliance should be factored into the BNE. We know that certain measures can be taken at sites to positively affect run hour limits. However, these costs are not currently accounted for, and we expect environmental compliance costs will increase over time, e.g., for existing units which as they age will have efficiency losses that will affect environmental compliance, or repowering where BAT compliance will be required, as well as cost of providing more compliant new units. The provision is within the Net CONE options, and it is not being utilised when it is clear that the investment landscape from 2025 onwards cannot be the same as the investment landscape now.

In our view, the goal of a revised BNE methodology must be able to signal a future vision for the BNE considering more fully ACER methodology, demonstrating value of existing generation, acknowledging the investment landscape pushing investment into low carbon/net zero technologies and acknowledging the potential for redevelopment/renewal at existing sites to help meet security of supply and future low carbon/net zero ambitions.

2.3. The BNE analysis

We support the EAI position that assumptions need to be reassessed, but the proposed BNE is not a substitute for a significant and holistic review of the Net CONE in 2023 to set a framework that is fit for purpose for the pathway to 2030 and beyond.

With reference to the CEPA report, two approaches to CCGT Infra-Marginal Rent were considered by the consultants. One with an optimistic projection of IMR, and another more cautious forecast that takes account the external factors, e.g., RES penetration, that should have a downward effect on the IMR of a CCGT. Such factors affect the running regime that could be assumed for a new entrant (definitely not a base assumption of 65% as mentioned in the CEPA/Ramboll report). This is especially true for a CCGT which would otherwise have expected to be a more frequent running baseload/mid-merit style unit based on size and volume of capex seeking a return. As these external factors will affect the IMR of a CCGT, it is not rational in our view, why this more cautious forecast from CEPA has not been considered. This more realistic view of CCGT IMR would likely arrive at a different best new entrant plant which, in our view, aligns with the need at least for the forthcoming auction, to maintain investor confidence in the T-4 process and ensure entry of much needed capacity.

We have reviewed the CEPA/Ramboll analysis and have provided some commentary below. We support the Frontier Economics analysis of inputs and outputs. Fundamentally, assumptions must be reviewed, further modelling is required, and an outlook needs to be calculated year-on-year for the lifetime of assets identified. As demonstrated below, with only the factor of increased interconnection during the period, it is wholly inaccurate to assume a single capacity year extrapolation can truly express realistic and rational project risks and costs for a best new entrant, particularly over this forthcoming time horizon. All of the factors discussed below would be clearly considered, allocated a risk level or forecast cost in the financial/business case of a rational investor to support continued operation or new entry of a project.

Underestimated inputs to WACC

We can see from public indices in the Frontier analysis that assumptions in the CEPA/Ramboll report are underestimated and/or overly optimistic. Had assumptions been better accounted for this could demonstrate a reasonable eye to future requirements, changes in financing landscape, national and supranational binding requirements on industry, as well as shorter term factors like the Ukraine war and expected recessionary levels of inflation expected out to 2024 in the EU. All of which significantly improves investor confidence to continue or enter this market.

On the subject of inflation, we would point to the Frontier Economics analysis provided by EAI. This paper outlines the average inflation as predicted by various agencies across 2022-2024. Taking the forecasts from the Irish Central Bank for example, the average does not come near to the CEPA/Ramboll of a flat 2% projection, it would be hugely optimistic to consider that the actual average 5.7% rate between 2022-24 would be realistically at the level of 2% for 2025/26 chosen capacity year for analysis.

We would also like to point out that the use of solely German bond yields as a modelling assumption for such a significantly smaller market, is wholly disproportionate. We can agree with rationale to use Eurozone related metrics, but this cannot be used in pure form without appropriate adjustment to reflect the size of our smaller jurisdiction. Otherwise, it risks suggesting that bond yields are comparable with respect to return and risk, which cannot be unless they are expressed relative to the real market factors for Ireland and Northern Ireland.

Single capacity year extrapolation

On the point of a single capacity year analysis, we note that the approach was to utilise 2025/26 capacity year as the year for analysis, i.e., not even the capacity year related to the future auction. This has then been extrapolated with assumed flat projections for inputs such as inflation as well as outputs such as IMR. SSE supports Frontier Economics' assessment of this approach, below:

"This [2025/26 one year approach] is done instead of modelling the expected IMR for each year of the asset life, as would typically be done when considering such an investment. By extrapolating the one-year model output, the study assumes no real change in the IMR from 2026-27 to 2035-36 (and it is difficult to discern what assumptions are made beyond 2036)."

We would add that contrary to CEPA/Ramboll analysis, IMR is a highly subjective revenue stream based on the trading success of a market participant in what is a challenging market with a lack of effective forward markets and limited hedging opportunity. Given all the other investment considerations outlined in sections above and below, this confirms that there are significant variables affecting the degree of IMR for any given year. Therefore, a one-year snapshot assessment is not appropriate.

As below simply analysing the effect on IMR of increased interconnection, a single reference year extrapolation is highly inaccurate and unreflective of realistic costs and revenues for any of the reference technologies. A one-year extrapolation as also discussed in this response, is not realistic of how investors will forecast and inform investment decisions for existing operation or future entry.

We note that the CEPA analysis does concede that a reduction factor of some sort applied to IMR over time to reflect lower rents over time, given IMR is likely overly optimistic. We also note that there are optimistic projections for system services where the market to replace the existing DS3 is still uncertain and in fact, judging from a recent stakeholder event, will likely remain uncertain since delivery timelines are still not clear. It is our position that as above, there is provision and expectation under ACER requirements for a fixed and variable Net CONE per technology and for year-on-year adjustments to be provided for which could be modelled out for every year of an asset's life and could better reflect uncertainty. We would expect that for the period we are entering, all of these provisions are used to their fullest extent to appropriately anticipate the changing investor landscape, external drivers for alternative technologies and the impacts of changing fuel mix on capacity procurement in the CRM and on IMR earnings.

Increased interconnection
Using the RA public model, we have modelled the impact of interconnection on IMR as one example of factors that would push the need for a year-on-year analysis of investment and return for an asset.

Taking the average annual IMR of several large units: Great Island, Whitegate and Aghada, in comparison to the values for 2023 and with the introduction of significantly more interconnection, the following can be seen:

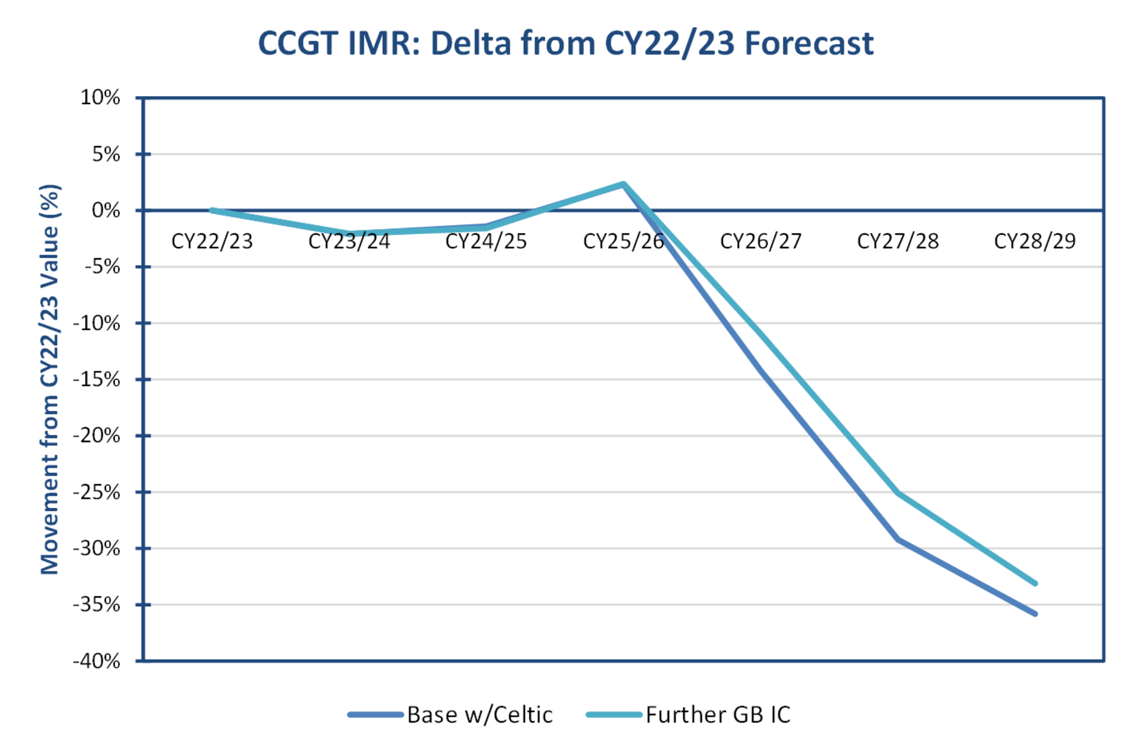
- There is a reduction 2024 and 2025, with a swing up in IMR in the year on which the single capacity year assessment in the CEPA report was based (2026).
- Thereafter, there is a significant and substantial decrease in IMR driven by the Celtic interconnector mainly
- When further GB related interconnection arrives, this can assist in the recovery of IMR on the basis of the SEM switching to a net exporter in later years

This demonstrates that a single year extrapolation cannot be relied upon and would not have been relied upon by investors if this model can be easily produced using the RA public model.

However, significant caveats must also be stated. The public model does not include the full value of renewables target build volumes as directed by Government and it would be inappropriate to assume that the additional renewables volumes can simply be directed as export. The drive and purpose of local capacity development must be to meeting local demand first and optimising of local capacity through infrastructure build out and treatment of firm access. The public model also would need more updating with respect to commodity prices and some missing non-fuel-based costs.

However, we feel the figure below is instructive in:

- demonstrating the relative movement rather than complete net value,
- that investors can conduct similar modelling on parameters that can be shown to have not been considered in the BNE proposal,
- that the approach therefore has not sufficiently modelled the decisions, considerations, and risks of a rational investor into the Net CONE calculation, and
- that a single capacity year extrapolation with assumed flat values for an extended period including inflation and IMR is not realistic



Model Scenario Inputs				
Interconnectors	**SEM To**	**Capacity**	**Base w/Celtic**	**Further GB IC**
Moyle	GB	500 MW	Included	Included
EWIC	GB	500 MW	Included	Included
Greenlink	GB	500 MW	Included: **Nov 2024**	Included: **Nov 2024**
Celtic	France	700 MW	Included: **Jan 2027**	Included: **Jan 2027**
MaresConnect	GB	750 MW		Included: **Jan 2027**
LirIC	GB	700 MW		Included: **Jan 2028**

Modelling of revenues

We note that an underlying assumption in the Net CONE calculation is that higher IMR revenues enjoyed by CCGTs will make them a cheaper unit by virtue of a greater proportion of capex cost expected to be recovered via the market in future years, rather than through the capacity contract guarantee. As we have demonstrated above, a single capacity year extrapolation allows for this IMR conclusion to appear rational. But it does not reflect the decision-making of a rational investor, and therefore cannot be seen to be a reliable approach for projects to make.

A year-on-year assessment of the fortunes of a project during its asset life and taking account of externalities like RES penetration and increased interconnection already demonstrate that IMR will be variable and unpredictable. There should be no offsetting of the cost of return against volumes of IMR or system services revenues potentially earned. This distorts the principle of the CRM to incentivise new entry since the market could not provide sufficient signals for this capacity to enter (i.e., the implication is that market revenues are not in fact sufficient alone). IMR is highly subjective and as above, is hindered by several factors in the SEM. As for system services, these revenues cannot be forecast as anything but benign or zero revenues —since investors have no future framework in place with any credibility at present to forecast such earnings. Therefore, it is inappropriate to include these as an upside to offset the return on capex cost of new projects.

Omitted baseline assumptions
We would expect like Frontier Economics have outlined, that increased RES penetration since the last BNE was set in 2018, should have been factored into the base case assumptions for the modelling. Many other changes since 2018 should have also been reflected, such as achievement of 75% SNSP. Thereafter, RES penetration including the target 7GW of offshore wind and targets up to 100% SNSP should have been factored into realistic modelling of future revenues and running regimes. Furthermore, national targets regarding carbon taxes, carbon budgets and renewables development were not included either in future forecasting or as part of post-2018 baselines. We would expect like Frontier Economics that RES penetration will have a downward impact on IMR for any conventional units but most especially on a CCGT with a higher load factor expectation. This impact on IMR is wholly inappropriate to exclude where we have the introduction of the RESS and ORESS schemes which solidify the sustained procurement and delivery of additional renewables.

Other assumptions missing in market baseline construction are expected impacts of inflation on supply chain and specific construction costs. In our view, the landscape for procurement of equipment, associated pressures relating to inflation and supply shortages are not articulated though it is clear these have developed post-2018 and may continue.

Annual Run Hour Limits
We note the disparity between derating for NI units versus ROI units. We also note the statement that ARHL only apply for NI units. As per the information note published regarding the matter, in December 2021:

The SEM Committee wish to clarify that the EPA have confirmed that with regards to licencing processes in Ireland, technologies other than a Combined Cycle Gas Turbine (CCGT) can be compliant with the BAT Conclusions for LCP without being subject to an ARHL of 1,500 hours

This suggests that in fact OCGTs in Ireland can be compliant, but CCGTs cannot be. We note from the most recent Winter Outlook and Generation Capacity Statement from EirGrid, the largest capacity shortfall lies in Ireland. Yet the BNE being proposed is a CCGT, where the EPA above seems to be suggesting that technologies other than CCGTs can be compliant without being subject to run hour limits.

Furthermore, the decision[9] to apply additional de-rating factors to new capacity for the forthcoming T-4 auction never suggests there is a difference in treatment between NI and ROI. Therefore, the cost differential arising from different de-rating given the assumption on NI units are ARHL, does not make sense. This would affect the overall cost comparison on OCGTs and CCGTs.

Solution: In our view, the approach to tackle all these identified issues in BNE analysis would be two-pronged. In the short term, a significant review of the assumptions underpinning the modelling for this reference technology. More fundamentally, consideration of a more holistic review of the Net CONE BNE which may include as suggested by Frontier Economics or EY, price caps only by exception, relaxed USPC mechanism or a levelised cost of capital[10] approach as in GB, and/or the adoption of a capex only focussed auction to cover what is intended—the cost of delivery.

2.4. BNE for future transition
The current and proposed BNE are not fit for purpose in procuring such technology that both meets the function of the CRM to procure for security of supply, whilst also encouraging this being done in a low/zero carbon manner (to meet regulatory, national, supranational obligations). So close after COP27, it is clear that more action needs to be taken now and as investors we are patently aware that the lead time for the sorts of changes required by 2030, are falling around the mid 2020's, i.e., 2025-2027. Any later, and targets risk not being met by generation procured in the CRM. The CRM is a critical factor in procuring the generation needed to deliver a decarbonised energy system and to support renewables penetration whilst also meeting security of supply.

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9 T-4_2026_27_Parameters_Decision_Paper_0.pdf (semcommittee.com)

10 Electricity Generation Costs 2020 (publishing.service.gov.uk)

By 2030, the Irish government is looking to meet ambitions emissions targets and increase the development of onshore and offshore wind. There are specific targets for the energy sector too which we have not seen borne out to date in any specific market signals for the development of the type of technologies that could meet these ambitions. SSE is committed to a net zero future and therefore, we find it frustrating to see a Best New Entrant without any future-looking vision where it is setting the reference unit for procurement from 2026 onwards (set for an assumed 4-to-5-year timeframe), aligned to the same time horizon as 2030 targets.

With reference to a MAREI study[11] regarding the costs associated with meeting carbon budgets, it is clear that there will be an impact on investment costs relating to meeting carbon budgets in the procurement of generation or conversion of existing generation in the energy sector. The energy sector traditionally has had the responsibility for shifting the lion's share of emissions given their significant reliance on fossil fuels. The expected cost differences in meeting carbon needs can either be factored over a longer time horizon to protect customers from price shocks, or much later in the decade where it is likely to have a significant impact. Where the RAs continue to have a short-term view of cost minimisation (versus future benefit for customers which will be accompanied by lower per unit costs), there is a danger that the needed investment will not be made in time, or the significant price shocks later in the decade will mean no investments in low carbon will be signalled at all. None of this has been considered in the assumptions or modelling relating to the setting of Net CONE, despite the fact that it is clear to most of industry since Clean Energy Package that the BNE is not appropriate for a low carbon future.

We would also concur with recent publications from Wind Energy Ireland[12] which confirm high acceleration of wind needed to meet carbon budgets, which as we have outlined, has an impact on modelled IMR, running regime expected for CCGT or other units entering or existing in the market, and the fuel mix that should be focussed on procuring via the CRM. It is also our view that the Climate Act requirements and Clean Energy Package obligations to deliver on carbon targets and budgets are directly for agencies such as the CRU to address. Yet the approach with the BNE is to apply the same general approach as before.

It is clear for instance from shifts in shareholder appetite and corporate commitments that there is a deal of focus and support for companies that are focussed on a sustainable future for the benefit of societies and customers. The focus towards sustainable finance and away from fossil fuel investments[13] is set to continue in line with a focus on a just transition. These are the same external appetites and financing approaches that energy projects are responding to and are reliant on for financing. Yet, none of this is considered in the context of the CRM which we consider is short-sighted where the future capacity years for delivery of capacity signalled by this BNE reference unit is out to 2030 and beyond. A short-term view of BNE leaves procurement mechanisms in deadlock, siloed by technology, and outdated.

Solution: we support a review of the BNE post March 2023 (after the T-4 2026/27). We are strongly of the view that the SEMC are risking deterring investment with the current approach to BNE remaining in place for the fundamental changes we expect out to 2030. We would favour price caps by exception as recommended by the EY review of the CRM. We can see the potential for levelised cost of capital reference prices as a mechanism to support the procurement of a more diverse and sustainable fuel mix. We can see in GB that clearing prices remain lower than those experienced in the SEM CRM. We would be confident therefore that alignment closer to aspects of the market design in GB is not risking exceptional clearing prices given the absence of rigid and mandatory price caps.

We consider that the timing is critical and arguably significant review of the BNE in 2023 could mean some proportion of missed targets with respect to carbon abatement in the energy industry. It would be a case though of "better late than never". In line with the EAI we strongly recommend the SEMC consider this as a separate and urgent workstream as part of a clear roadmap of changes to the CRM but delivered within 2023 to ensure that the energy industry has a chance to respond to investment drivers towards fossil fuel abated/alternative lower carbon conventional sources of generation.

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[11] The challenge of allocating Ireland's carbon budget among sectors - MaREI

[12] New report sets out carbon budget for electricity sector (windenergyireland.com)

[13] Green Financing | UNEP - UN Environment Programme; Sustainability Investing on the Rise | Morgan Stanley;