# Best New Entrant – Net Cost of New Entry (BNE-Net CONE)

**Consultation response**

November 2022

# Executive Summary

EirGrid and SONI welcome the SEMC's consultation SEM-22-076. The TSOs wrote to the SEM Committee in November 2021 outlining several concerns around the ability of the Capacity Market to attract the right investment to meet our near-term and indeed enduring capacity needs. The TSOs have highlighted (through engagement with the Regulatory Authorities) that it is our view that changes are needed in advance of the T-4 2026/27 Capacity Auction to allow enough time to provide the adequate market signals and support investor confidence within the Capacity Market.

We acknowledge that the SEMC is carrying out a review of the 'Best New Entrant' in advance of the T-4 2026/27 Capacity Auction. However, the TSOs do have concerns that the current BNE methodology is not robust enough to enable the Single Electricity Market to attract the right volume and type of capacity. The TSOs note that it is critical that the SEMC brings about other urgent market reforms so these can be factored into how the future BNE is calculated. This is important for delivering a balanced portfolio of plants to meet the needs of an All-Island electricity market with 80% of electricity coming from renewables and to meet the stringent carbon budget in Ireland and new carbon budgets that are expected in to be in place next year for Northern Ireland.

As part of Shaping Our Electricity Future and other analyses carried out by the TSOs, we are of the firm view that for 2030 we need a balanced portfolio of technologies to meet our system needs, renewable targets, carbon budget targets and to help mitigate against weather related events such as a "dunkelflaute" (extended periods of very low to no renewables output). A balanced portfolio would include renewables, interconnection, long duration storage, high availability demand side management, 'clean gas' ready open cycle gas turbines and multi-shaft combined cycle gas turbines.

As set out in the consultation paper, the TSOs have several major concerns as to the appropriateness of the input assumptions for the BNE analysis and therefore the net CONE outcomes. The TSOs would like to focus on the following concerns and, where relevant, make some recommendations:

1) The CEPA and Ramboll inframarginal rent (IMR) projections for CCGTs are overall too optimistic over the 20-year period, principally due to the clear government policy directions to drive renewable integration to 80% RES-E in Ireland and Northern Ireland. As part of this response, the TSOs are providing alternative projections for inframarginal rent, based on production cost modelling (supported by AFRY), suggesting a reduction of more than 10€/kW on a de-rated basis (in 2026 money terms).

2) Our own independent review (led by AFRY) of current CAPEX for CCGTs and OCGTS suggests that these should be higher than those proposed by the CEPA/Ramboll report; cost of materials and labour have increased considerably in the last couple of years, and there are now additional requirements for conventional thermal generation for limiting the emissions intensity in the future.

3) We agree with the choice of a CCGT as the reference technology with the lowest net CONE. However, given the above, we estimate that the net CONE for a CCGT in Ireland for 2026/27 is €128/kW (de-rated) in nominal money terms.

4) The TSOs also note the uncertainties within global economic systems and suggest that the SEMC at a minimum continue to ensure that the net CONE is indexed linked over the forthcoming auctions.

5) It is of critical importance that the BNE is appropriately dimensioned to the Auction Price caps to ensure that there is enough opportunity for investors to manage the asymmetrical risks. Investors face a range of uncertainties and commercial issues that are more impactful now than at any other time, noting that during recent years we have had relative economic stability and low interest rates. At this time, it is important that investors have room to manage risks through their bidding strategies, therefore allowing them to hedge their uncertainties and risks. It is of crucial importance that the market should allow competition to drive efficiency rather than being overly prescriptive on auction price caps, particularly as we need to deliver a range of new and emerging low carbon technologies that can provide an enduring solution to the security of supply challenge. New technologies are needed to create a balanced portfolio necessary to manage a power system with world leading levels of renewables in the electricity system.

   At this time of capacity scarcity there needs to be serious consideration of using higher price multipliers for the auction price cap (at least x1.75 to x2.0), increases to existing price caps and, additional intervention options may be required to deliver the necessary technologies.

6) It is the TSOs' view that the current BNE proposal is not future proof. It is essential that any investment in new fuel burning capacity should be future proofed to meet our enduring security of supply needs. For example; we must ensure that gas turbines or engines are renewable gas ready and the incremental CAPEX for this should be factored into any design. Furthermore, we need to incentivise combined cycle gas units. Where possible, these need to be flexible through multi-shaft design with a by-pass stack instead of a single shaft. Looking into the longer-term projections, maximising flexibility of new CCGTs at the design stage will provide the system operators with a fit for purpose power system with enhanced system flexibility; this is particularly important as we are on a no regrets pathway to a high renewable electricity system.

   We welcome guidance from the SEM Committee on how it plans to address this remuneration gap, which ensures that the longer-term green credentials of power plants are incentivised to invest at the design to future proof their long-term investment. It is vital that we ensure the investments are made early to ensure enduring long-term investment protection, security of supply, operational capability and flexibilities within the electricity system.

7) The BNE review demonstrates the investment challenges for energy storage. The current market mechanisms, including the Capacity Market, are not providing the correct signals to invest in long duration storage. Our Shaping Our Electricity Future analysis into a balanced portfolio has demonstrated the need for longer duration storage. Failure to invest in storage will mean we will fall short of our renewable and emissions targets. Furthermore, lack of investment in storage will result in higher levels of oversupply of renewables, making investment in more renewable capacity uneconomic.

   There is a clear market failure that needs to be remedied in the final decision; it means there is an urgent remuneration gap which needs to be addressed. One potential solution is to consider a parameterisation of the auction to include a specific volume and/or technology specific price cap that will provide a route to market for emerging long duration storage projects that are deemed realistic and deliverable. We welcome guidance from the SEM Committee on how it plans to address this gap.

8) The Future Arrangements for System Services is very uncertain. As it stands, investors do not have confidence in future system service revenues to the detriment of wider system benefits. The TSOs are disappointed that there is currently no agreed detailed design or implementation plan for the replacement of DS3 System Services from the SEM Committee. This workstream needs to be urgently progressed with a robust action plan developed to create system service products that investors can have confidence in, so that they can gain an understanding of how the new arrangements will work for their investment, consequently increasing competition in the market and improving market efficiency, therefore bringing clear benefits to the wider electricity ecosystem. The TSOs would welcome a comprehensive vision and implementation plan from the SEMC and the Regulatory Authorities which details all the market changes which are required to deliver the Governments', European and Great Britain policies.

Finally, the TSOs want to conclude by stating that a balanced portfolio of onshore and offshore renewables, new renewable gas ready flexible CCGTs and unrestricted OCGTs, long duration batteries, highly available demand side management, and interconnection complimented by low carbon inertia services are needed to enable the delivery of a secure transformation to an emissions target compliant power system that delivers at least 80% RES-E by 2030. The SEMC should give strong consideration to technology specific auctions to ensure that a balanced portfolio is delivered. The TSOs are open to engaging collaboratively with the SEMC and the RAs.

# Introduction

EirGrid, the Transmission System Operator (TSO) in Ireland, and SONI, the TSO in Northern Ireland, are obliged to jointly administer the operation of the SEMC's Capacity Market, in accordance with the Capacity Market Code (under section B.6.1.1 Joint Administration of this Code and Capacity Market).

The Commission for Regulation of Utilities (CRU), which regulates the electricity system in Ireland, is responsible for the security of supply of electricity in Ireland. The Department of Economy (DfE) in Northern Ireland is responsible for the Security of Supply in Northern Ireland. The Utility Regulator is the economic regulator for the electricity system in Northern Ireland. Collectively the CRU and the UR are referred to as the Regulatory Authorities (RAs).

The Single Energy Market Committee (SEMC) is the decision-making authority for all matters related to the integrated Ireland and Northern Ireland electricity market (the 'Single Electricity Market') and provides a formal governance role in the approvals relating to the parameter setting of each Capacity Market Auction along with the associated approvals of the final capacity requirement volume sets for each capacity auction.

The purpose of the Capacity Remuneration Mechanism (CRM) is to allow generators within SEM to recover their fixed costs. This includes investment and fixed operational costs. The capacity mechanism is there to procure sufficient capacity at a competitive price to meet current and future demand and operational requirements.

A well-functioning CRM is a vital component of the overall performing SEM. It should support efficient and effective delivery of existing and new capacity in creating a balanced portfolio of technology that is required to deliver a reliable power system on a pathway to 80% RES-E with meeting government targets for emissions. An effective Capacity Market is critical to Ireland's and Northern Ireland's economic growth. It is paramount that a Capacity Market should provide clear, unambiguous signals to investors to allow them to commit to and invest in credible projects. The purpose of the Capacity Market is to ultimately drive investment in new enduring sustainable capacity. The Capacity Market should create a pathway to ensure that new capacity is connected to the grid, that it is made fully operational. System operators need to have sufficient capacity to operate a reliable power system for future generations and encourage confidence in the economies of Ireland and Northern Ireland, thereby supporting wider economic growth. EirGrid and SONI are, on record, noting that the current CRM mechanism is not fit for purpose.

Furthermore, additional market reform is required as we transform our power system to deliver on 80% RES-E and emissions targets that are now legislated for in Ireland and Northern Ireland. The TSOs have clearly communicated through Shaping Our Electricity Future the need for changes in wholesale electricity markets. The TSOs once again re-state the need to ensure that Future Arrangements for System Services (FASS) are implemented, so that the operational capability of a balanced portfolio can deliver the range of new services required to manage a power system of 80% RES-E. Power system reliability is no longer only about the growth in peak demand and the loss of thermal power units. The All-Island power system must have a balanced fleet of technologies, including renewable gas ready flexible CCGTs and OCGTs, long duration batteries, highly available demand side management and interconnection to manage the uncertainties of renewable ramping within day and extended multi-day periods where the wind does not blow and the sun is not shining.

At the present time the capacity adequacy outlook in SEM is very challenging. Since 2016, the Generation Capacity Statement has clearly signalled a tightness in the balance between supply and demand and that existing plants will close due to environmental regulations and the need for new replacement capacity. In 2021, there was an additional event where two large generators were forced off the system causing short-term issues in managing capacity margins. This demonstrates the challenges of running a power system that is facing year-on-year growth in demand and the need to retire some of the existing units. This is a separate matter and should not be conflated with the functioning of the CRM system.

The current security of supply threat was made very clear in 2021, when circa 650 MW of capacity holders terminated their Capacity Market positions. The failure of the Capacity Market to deliver this new capacity triggered the need to re-assess system adequacy in Ireland. EirGrid, as a result and in accordance with Regulation 28 of SI 60 of 2005, issued correspondence to the CRU in June 2021, outlining the seriousness of the threat to security of supply for Ireland along with a series of recommended measures required that should be to be actioned to address that threat. This letter followed correspondence issued by EirGrid to CRU in March 2021, outlining security of supply concerns. It is worth noting that over the period 22/23 to 24/25, circa 700MW of de-rated capacity that was scheduled to connect under the CRM has terminated to date.

The key changes we have identified when comparing to the previous determination are as follows:

- the suggested BNE (the technology with the lowest net CONE) is now a CCGT, instead of an OCGT – this was, however, also the case in the consultation paper for the previous determination, and was subsequently re-examined in the final decision (switching marginally to an OCGT);
- there is a substantial drop in the net CONE for a CCGT, driven by an assumed increase in market net incomes (inframarginal rent from the energy market and DS3 income); and
- a very strong increase in the net CONE for OCGTs in Northern Ireland on a de-rated basis as a result of lower de-rating factors for OCGTs in Northern Ireland (given the expected run hour limitations and ability to contribute to the capacity margins).

From our perspective, the BNE choice should result in CRM parameters that can help deliver a ‘balanced’ generation portfolio, which:

- ensures security of supply in terms of generation adequacy (having enough megawatts to meet peak demand);
- has the wider desired capabilities for secure operation of the system; and
- helps us achieve our key policy objective of meeting the government’s renewable generation and carbon emissions reduction targets.

The CRM on its own cannot deliver on all the above objectives but is the most important tool we have at the moment for protecting our generation adequacy. It is critical that, going forward, markets are reformed to support the delivery of renewable electricity and emissions targets that have been set by both the Irish Government and the Northern Ireland assembly.

There are other markets in place (or are currently being developed) to help with the other two objectives (most notably the FASS). The choices made for the CRM can help support the transition to a world where conventional thermal generation has a rather limited role, and not block technologies that are needed as part of a ‘balanced portfolio’.

As TSOs, through our Shaping Our Electricity Future analysis, we have identified the need for a future generation portfolio with varied operational capabilities, including:

- ability to provide inertial response at low levels (or even zero) active power output;
- ramping capability over various timeframes, and, in particular, a need for a product that has a longer duration than the current RM1, 3, and 8; and
- controllable capacity that can generate for an extended period of time when RES output is unavailable because of weather conditions with the lowest possible impact on carbon emissions.

To this end, we are developing markets under the Future Arrangements for System Services that will drive investment to provide the TSOs with the operational capability that is required to deliver 80% RES-E and emissions carbon to complement the wholesale energy markets and a CRM. It is the TSOs' view that we need to deliver a balanced portfolio of renewable gas ready CCGTs and OCGTs, long duration batteries, highly available DSUs, interconnection and new system service providers such as Low Carbon Inertia Services and reserve batteries to support government ambitions to achieve our policy objectives in an effective and efficient way.

We acknowledge that the SEM Committee has carried out a review of the Best New Entrant in advance of the T-4 26/27 Capacity Auction. However, the TSOs do have concerns that the current BNE methodology is not robust enough to enable the Single Electricity Market to attract the right volume and type of capacity.

# Choice of the reference technology

CEPA and Ramboll have explored additional technologies compared to previous determinations (including Reciprocating Internal Combustion Engines and battery storage). In the past, there has been some criticism when it comes to opting for the lowest net CONE technology. There is uncertainty around all cost estimates, therefore, opting for the 'cheapest' option may impact the price resulting in delivery of a lower volume than the desired level of de-rated capacity required to meet the capacity requirement and the reliability standard. The RAs do have the auction price cap multiplier that is used to determine the price cap to provide for 'headroom'. However as it stands, if the relationship between multiplier and viable technology options available to the market does not match at times of scarcity, there is a significant risk that the market will forfeit, delivering a lower volume of capacity than what is sufficient to meet the desired reliability target.

When it comes to the new technologies that have been assessed, the analysis shows that RICE and BESS technologies are not cost competitive with CCGTs and OCGTs for ensuring there is adequate generation capacity on the All-Island system, and the TSOs' balanced portfolio analysis supports this finding.

That said, the TSOs' analysis on a balanced portfolio clearly shows that we expect a range of conventional and new technologies to play a role in securing the transformation of the power system. Our latest analysis, on an All-Island basis, highlights a need for at least 1.0 GW of new long duration storage (greater than 6 hours) and 2.1 GW of shorter storage (less than 6 hours) to deliver by 2030 in support of 80% RES-E targets. The TSOs expect there to be a role for storage to provide operational support underpinned by Future System Services and help with RES curtailment.

The demand curve is a key part of the CRM auction. The purpose of the demand curve is to allow procurement of the 'target' capacity volume for a specific reliability standard; at what is deemed to be an efficient price, the basis of this is shaped by the net CONE analysis. At times of capacity surplus, there is an option to procure more capacity beyond the standard, but at a lower price, or during time of scarcity, the demand curve may deliver a lower volume of capacity than desired but at a higher price. This provides an economic signal to the market to deliver new capacity. If the net CONE is not appropriately defined, there is a risk of inefficiencies:

- if the net CONE is set too high, the whole demand curve is shifted up and we may be in a position where we are procuring too much volume at an inefficient price;
- if the net CONE is set too low, the whole demand curve is shifted down and we risk not procuring sufficient volume of capacity, whilst also paying an inefficient price.

The current auction process provides for some flexibility in the determined capacity requirement volume depending on the time horizon of an auction. In theory, a T-4 may set parameters to procure a lower capacity volume for the mid-term (four years ahead), which is followed up with short term auctions (e.g. a one year-ahead auction) to top-up the required volumes, when there is more certainty on short-term forecast trends. However, at present, there are security of supply concerns within the local capacity constraint for Ireland and Northern Ireland, which effectively means that there are challenges in delivering sufficient new capacity to meet the jurisdictional requirements. To this end, the RA's parameterisation of the Capacity Market needs to be cognisant of prevailing market conditions to encourage a balance of technology deployment; within realistic project time lines, at the right locations and ultimately at the right price to ensure that the long term security of supply issues within the SEM market are addressed.

The three pillars of the electricity trilemma remain security of supply, decarbonisation and affordability. In our role as TSOs, we need to operate a safe and secure power system while maintaining security of supply. We do this by monitoring if there is sufficient capacity in the short to long term to balance supply and demand, and to meet our operational security requirements, thereby ensuring that we meet our reliability standards for each jurisdiction. As TSOs, it is important to consider the entire electricity market structures and to this end it is critically important to ensure that the value chain is fully understood across the various components of each electricity market including FASS, energy only markets and CRM. Taking a view of the whole electricity system means we can ensure we have a power sector that is delivering on decarbonation goals, security of supply, in an economic manner and technologically capable of handling 80% RES-E by 2030.

The choice of the reference technology does not mean that all new entrants will be based on that specific technology. This is evidenced by the results from previous CRM auctions with storage and DSUs having been awarded capacity contracts. Technology costs change in time, and so do underlying market conditions. We expect market players to react to changes in costs, electricity prices and the presence of other markets.

On balance, we therefore do not believe we should diverge from the broader principle of choosing the technology with the lowest net CONE as the reference technology. However, given there is uncertainty around cost estimates and projected net income going forward, we should err on the side of caution and be more open to ensure the market is flexible enough to attract a broad range of technologies that will support the delivery of a balanced portfolio.

# Capex and Opex estimates

CCGT and OCGT Capex appears to be lower in real money terms in this new determination compared to the previous determination. When comparing the total Capex for OCGTs and CCGTs in the Poyry 2017 BNE and the CEPA 2022 BNE, we see that:

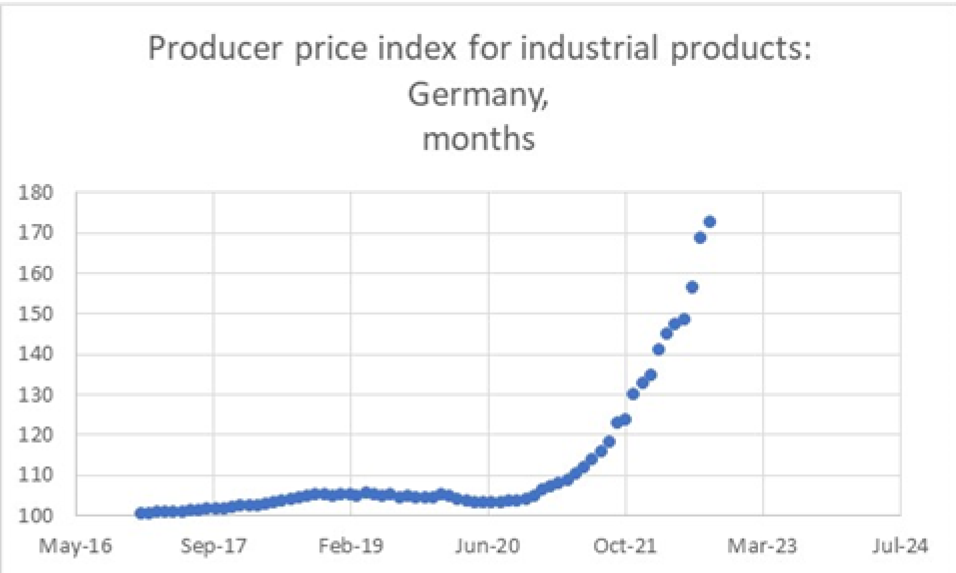
- the overall OCGT Capex is around 16% lower; and
- the overall CCGT Capex is around 4% higher;
    - the assumed CCGT rated megawatt capacity of the CEPA 2022 BNE is also higher, which means that the relative Capex under this new determination is actually lower.

This is surprising for two reasons:

- equipment costs have gone up over the last year; and
- any new entrant should be assumed to be 'hydrogen-ready' to comply with the EU Taxonomy requirements.

We will focus primarily on the EPC cost estimates as these are the key driver of the overall Capex, as well as (indirectly) some of the additional cost components. The EPC costs presented do not appear to fully take into account the inflationary pressures and equipment cost increase over the last year.

The OCGT EPC price estimate in BNE 2022 is around EUR 79m (2022 price level). This is around 15% lower than prices in BNE 2017 (and BNE 2016 as prepared by CEPA/Ramboll). There is nothing to indicate that prices have softened since the BNE 2017 report was published. In contrast, all the evidence points to significant price escalation having taken place, impacting the cost of both labour and equipment. In terms of equipment costs, the chart below shows the German government Producer Price Index for industrial products over the period Jan 2017 to Oct 2022. We can see that whilst the index has been very stable historically, it has increased dramatically since the beginning of 2021 as a result of the pandemic initially and the conflict in Ukraine subsequently. The conflict in Ukraine has impacted energy prices, metals prices, transport costs etc., all which feed into higher product prices for industrial equipment.




We therefore propose the following changes to the assumed EPC cost:

- revert to the specific EPC cost from the previous determination; and
- 'scale up' this EPC cost in line with the Producer Price Index for industrial goods and the labour cost index.

This means the specific EPC cost would be:

specific EPC = previous specific EPC x [79%xPPI+11%*LPI+10%]

This assumes that 79% of the overall EPC is linked to materials, 11% is linked to labour (EPC contractor's staff for detailed design and project management).

The table below shows a revised estimate for the EPC cost of a similarly sized OCGT (as that investigated in the CEPA/Ramboll report) in Ireland.

| Description | Unit | Value | Remark |
|---|---|---|---|
| EPC cost BNE 2017 | EURm | 93 | As per BNE 2015 and BNE 2017 reports |
| Materials index | % | 145% | As per German PPI for industrial products over period 1 Jan 2018 to 1 June 2022 |
| Labour index | % | 113% | 2% per annum for 2018, 19, 20 and 21 and 4% for H1 2022 |
| Weighting materials index | % | 79% | Typical |
| Weighting labour index | % | 11% | Typical |
| Other | % | 10% | Typical |
| Total escalation | % | 137% | Calculated from above |
| Implied EPC cost for BNE 2022 | EURm | 127 | Calculated from above |

The table below shows a revised estimate for the EPC cost of a similarly sized CCGT (as that investigated in the CEPA/Ramboll report) in Ireland.

| Description | Unit | Value | Remark |
|---|---|---|---|
| EPC cost BNE 2017 | EURm | 284 | As per BNE 2017 report |
| Materials index | % | 145% | As per German PPI for industrial products over period 1 Jan 2018 to 1 June 2022 |
| Labour index | % | 113% | 2% per annum for 2018, 19, 20 and 21 and 4% for H1 2022 |
| Weighting materials index | % | 70% | Typical for CCGT |
| Weighting labour index | % | 20% | Typical |
| Other | % | 10% | Typical |
| Total escalation | % | 134% | Calculated from above |
| Capacity escalation | % | 105% | 105% is the ratio of 470MW (CEPA/Ramboll) and 447MW (previous determination) |
| Implied EPC cost for BNE 2022 | EURm | 400 | Calculated from above assuming a move to a 470MW capacity (EPC cost BNE 2017 x 134% x105%) |

The resulting revised EPC cost for OCGTs and CCGTS in Ireland and Northern Ireland is shown below. For the Northern Ireland values, we follow the same approach, and the only difference is the starting point, which is based on the BNE 2017 determination (and included some small differences between Ireland and Northern Ireland).

| | Republic of Ireland | | Northern Ireland | |
|---|---|---|---|---|
| | OCGT | CCGT | OCGT | CCGT |

| | | | | |
|---|---|---|---|---|
| CEPA | €79,100,000 | €315,900,000 | €77,800,000 | €313,600,000 |
| Revised | €126,787,018 | €399,949,684 | €126,032,437 | €401,357,461 |

# Weighted average cost of capital

CEPA has used the commonly used formula that weighs the cost of debt and cost of equity with an appropriate gearing to determine the Weighted Average Cost of Capital (WACC). From then on, it used the CAPM approach for the cost of equity, and the debt premium is defined as the risk-free rate plus a debt premium.

In general, we believe that market sentiment has shifted over the last few months and the cost of capital has increased. The analysis presented by CEPA will need to be updated to reflect this, and in particular the change in the risk-free rates. CEPA also recognises this and proposed to update the risk-free rate and the tax rate for Northern Ireland in the final decision.

## Gearing

CEPA proposed the use of a 40%/60% debt-to-equity ratio. This is in line with the previous determination, and we believe this can continue to be used going forward.

## Risk-free rate

We note that there have been significant movements in the risk-free rates over the last 3 months and since the research was undertaken by CEPA. The risk-free rate as of 15 November 2022 is:

- 3.8% for the UK; and
- 2.1% for German bonds (which could be used as a proxy for the Irish risk-free rate).

We recommend revising the risk-free rates used in the determination of the WACC to be aligned with current bond yields and wider sentiment on the evolution of interest rates.

## Cost of debt

Risk-free rates have a direct impact on the cost of debt, and propose to increase the cost of debt to be in line with the current bond yields. We can therefore retain the debt premium implied by CEPA. The resulting cost of debt is:

- 4.5% for Ireland; and
- 5.3% for Northern Ireland.

## Equity Risk Premium

Given the proposed increase in the risk-free rate, the Equity Risk Premium should be also adapted to reflect this increase.

## Asset beta and equity beta

CEPA has chosen to adopt an asset beta that appears to be the median of the range that represents utilities. We do, however, believe that it would be more prudent for the purposes of the BNE determination to adopt an asset beta that is close to the upper bound and retain the 0.69 from the previous determination. The equity beta then also is impacted given its linkage to the asset beta.

## Taxation

As CEPA has already pointed out, the corporation tax in Northern Ireland is now set to remain at 19% and not to be increased to 25%. This would need to be reflected in the final decision.

## Summary

The table below shows the values (including the resulting WACC) shown in the CEPA report and our recommended changes. These proposed changes are in line with the current market expectations. Interest rates have gone up since the last determination and based on our interactions with the industry, so has the cost of capital. Given this and the fact that investment in some forms of generation (GTs/OCGTS) is becoming 'riskier' given the uncertainty around running hours and market volatility, we believe the assumed WACC should actually increase (rather than drop) compared to the previous determination.

| **Element** | **Republic of Ireland** | | **Northern Ireland** | |
|---|---|---|---|---|
| | **CEPA** | **TSOs Analysis** | **CEPA** | **TSOs Analysis** |
| | | | | |
| Gearing | 40.0% | 40.0% | 40.0% | 40.0% |
| | | | | |
| **Cost of debt** | 3.5% | 4.5% | 4.6% | 6.3% |
| | | | | |
| Risk-free rate | 1.1% | 2.1% | 2.1% | 3.8% |
| Equity Risk Premium (ERP) | 7.6% | 8.6% | 7.4% | 8.8% |
| Asset Beta for energy industry | 0.55 | 0.65 | 0.55 | 0.65 |
| Equity Beta | 0.92 | 1.03 | 0.92 | 1.001 |
| **Post-tax Cost of Equity** | **8.1%** | **10.9%** | **8.8%** | **12.6%** |
| Taxation | 12.5% | 12.5% | 25.0% | 19.0% |
| **Pre-tax Cost of Equity** | **9.2%** | **12.5%** | **11.8%** | **15.6%** |
| | | | | |
| **Pre-tax nominal WACC** | **6.9%** | **9.3%** | **8.9%** | **11.9%** |
| **Equivalent Vanilla WACC** | **6.2%** | **8.3%** | **7.1%** | **10.1%** |
| **Post-tax nominal WACC** | **6.1%** | **8.1%** | **6.7%** | **9.6%** |

# Inframarginal rent and DS3 income

One of the key drivers for the very low net CONE for CCGTs is the projected inframarginal rent (IMR) – assumed to be €87.85/kW-installed, and to remain at that level throughout the first 20 years of operation. This appears to be a rather unrealistic projection, especially given the expected future generation under the energy transition that is underway. There is an ambition of 80% RES by 2030 in Ireland, leaving little room for conventional thermal generation. Relatively high margins from the energy market are possible but would rely on the presence of reasonably high price spikes when operating.

To put CEPA/Ramboll's projected IMR in perspective, this would be the IMR captured by a CCGT assuming a high utilisation and a spark spread of around €11/MWh. Our modelling (support from AFRY) suggests that no thermal unit will operate baseload or at high load factors post 2030. This means that the average captured margin would need to be much higher to get to this IMR level. Although we do expect more price spikes in the future, we also believe that other forms of flexibility (such as BESS and demand side) will also help mitigate some of these price spikes.

CEPA appear to also recognise that assuming a flat IMR for 20 years is quite optimistic, and they suggest a sensitivity, which assumes that the IMR gradual drops to 0 by year 10 of operation. The resulting annual average IMR would then drop to €20/kW installed. This is a difference of around €65/kW-installed, and would more than double the net CONE of CCGT. We do recognise, however, than this may be overly conservative – there should still be some IMR available to thermal generating units after 10 years of operation.

Based on our own analysis, a new CCGT commissioned in the mid-2020s would initially start running close to baseload but would then very quickly shift towards more mid-merit and then peaking operation. We have estimated that, based on a central view, when it comes to commodity prices and a wider underlying capacity mix that is in line with the policy objectives, the inframarginal rent would start off at around 95€/kW-installed (in 2026 money terms), but would gradually drop to 70€/kW-installed (in 2026 money terms) by the 10$^{th}$ year of operation and to 60€/kW-installed (in 2026 money terms) by the 20$^{th}$ year of operation. This is based on AFRY's production cost analysis we have undertaken out to 2045, and meets Ireland's and Northern Ireland's renewable ambitions of 80% RES by 2030.

It is much easier to estimate expected income from the provision of System Services under the current regulated arrangements, which rely on regulated tariffs (on the assumption that tariffs and the various multipliers remain unchanged). However, going forward, the Future Arrangements for System Services will mean the introduction of a competitive market with prices determined by underlying market forces. Although we do expect that the overall expenditure for System Services will increase to reflect the need for such services to enable operation with higher weather variable RES generation, the value will shift towards low-carbon provision. We would therefore be more conservative when it comes to the expected System Services income from conventional thermal providers. We would recommend a drop in the assumed System Services income for CCGTs for the purpose of the BNE determination with an assumed DS3 income of around €10/kW for CCGTs.

When it comes to income from System Services, it is much easier to estimate the expected income from the provision of System Services under the current regulated arrangements, which rely on regulated tariffs. However, going forward, the Future Arrangements for System Services will mean the introduction of a competitive market with prices determined by underlying market forces. Although we do expect that the overall expenditure for System Services will increase to reflect the need for such services to enable operation with higher weather variable RES generation, the value will shift towards low-carbon provision. We can therefore see merit in being more conservative when it comes to the expected System Services income from conventional thermal providers.

## Gross and net CONE

In all previous sections we have outlined a set of changes to the different parameters that are used for the determination of the net CONE for the different technologies. The key changes include:

- an increase in the WACC driven primarily by the higher risk-free rates;
- higher EPC cost assumption for OCGTs and CCGTs in line with underlying cost increases for equipment and labour;
- a slightly lower inframarginal rent for CCGTs to account for the drop in income captured given the lower running hours.

The table below shows the resulting gross CONE and net CONE on a de-rated basis for 2026/27 as presented by CEPA.

| | Republic of Ireland | | Northern Ireland | |
|---|---|---|---|---|
| *real 2026 money, €/kW* | GT | CCGT | GT | CCGT |
| Capex | | | | |
| Opex | | | | |
| **Gross CONE** | **96.4** | **181.9** | **236.5** | **185.9** |
| Inframarginal rent | -0.7 | -106.5 | -1.5 | -106.5 |
| DS3 income | -8.6 | -17.1 | -20.0 | -18.2 |
| **Net CONE** | **87.2** | **58.3** | **215.0** | **61.3** |

Based on our analysis these values would be as follows:

| | Republic of Ireland | | Northern Ireland | |
|---|---|---|---|---|
| *real 2026 money, €/kW* | GT | CCGT | GT | CCGT |
| Capex | 109.8 | 151.3 | 306.4 | 183.4 |
| Opex | 40.5 | 92.9 | 85.2 | 79.8 |
| **Gross CONE** | **150.3** | **244.2** | **391.6** | **263.2** |
| Inframarginal rent | -0.7 | -108.3 | -1.6 | -110.3 |
| DS3 income | -18.0 | -10.0 | -18.3 | -4.4 |
| **Net CONE** | **131.6** | **125.9** | **371.7** | **148.5** |

The above means in nominal money terms:

| | Republic of Ireland | | Northern Ireland | |
|---|---|---|---|---|
| *nominal money, €/kW* | GT | CCGT | GT | CCGT |
| Capex | 91.6 | 126.3 | 259.6 | 155.4 |
| Opex | 34.6 | 79.3 | 73.7 | 69.1 |
| **Gross CONE** | **126.2** | **205.6** | **333.3** | **224.5** |
| Inframarginal rent | -0.6 | -92.4 | -1.4 | -95.3 |
| DS3 income | -15.3 | -8.5 | -15.8 | -3.8 |
| **Net CONE** | **110.3** | **104.7** | **316.1** | **125.4** |

Based on our analysis, a CCGT located in Ireland has the lowest net CONE but is much closer to the net CONE of a GT and significantly higher than the CEPA and Ramboll report.