Best New Entrant Study 2022

Commission for the Regulation of Utilities (CRU) & Northern Ireland Utility Regulator (UR)

18 October 2022

FINAL REPORT

Important notice

Contents

1. INTRODUCTION

Cambridge Economic Policy Associates (CEPA) and Ramboll have been commissioned by the Commission for Regulation of Utilities (CRU) and Northern Ireland Utility Regulator (UR) (collectively, the Regulatory Authorities (RAs)) to produce a report to estimate the Cost of New Entry (CoNE) for the Single Electricity Market (SEM) Committee.

This report provides CEPA and Ramboll's independent estimate of the costs associated with the construction and operation of a Best New Entrant (BNE) power plant entering Ireland and Northern Ireland's Single Electricity Market (SEM) as well as the revenues that this unit may be able to achieve. Accordingly, the purpose of this report is to provide a Net CoNE estimate (i.e., costs net of revenues) in anticipation of the T-4 auction for the Capacity Year 2026/27. This report also provides an estimate of Gross CoNE which the RAs use to calculate the Reliability Standard in accordance with the relevant pan-European methodology[1].

CEPA and Ramboll have conducted CoNE estimate studies in previous years, with Pöyry Management Consulting also providing a CoNE estimate in 2018. We note that the context is different for this study, with the evolution of market arrangements in the Irish energy market and requirements from ACER around the estimation approach[2].

This report details our estimates for the various capital and recurring fixed costs that a rational investor would incur in the process of entering the SEM with a new generation unit. By combining the recurring costs with annuitized fixed costs, we have estimated Gross CoNE and Net CoNE for a number of shortlisted reference technologies. It is our intention that the methodology outlined in the remainder of this report is transparent to the extent that it is replicable for subsequent years of capacity auctions.

It is also important to acknowledge that due to recent financial and commodity market conditions, there is significant uncertainty around certain parameters used in the cost estimations throughout this report. We intend to update these parameters following consultation, and both CEPA and Ramboll welcome views from stakeholders across the market on the validity of costs used in this report.

The structure of the remainder of this document is as follows:

- **Section 2** explains the background and context behind the BNE, and summarises our approach to estimating its costs.
- **Section 3** outlines our approach to identifying and selecting reference technologies for our cost estimates.
- **Section 4** details our estimates for the BNE's capital and fixed costs for our selected BNE reference technologies.
- **Section 5** presents our estimates for the BNE reference technology's recurring costs.
- **Section 6** provides our approach and estimation of the cost of capital required as part of a BNE investment.
- **Section 7** sets out the revenues the BNE plant can expect to generate through the electricity market and provision of system services.
- **Section 8** considers all the assumptions set out in this report to generate estimates of Gross CoNE and Net CoNE.

[1] ACER, 2020, Methodology for the European resource adequacy assessment. Available at europa.eu.

[2] ACER, 2020, Methodology for calculating the value of lost load, the cost of new entry and the reliability standard. Available at europa.eu.

2. BACKGROUND & CONTEXT

Capacity markets exist in many electricity systems internationally to address the 'missing money'[3] issue. This situation occurs when wholesale energy and ancillary market revenues are insufficient to attract sufficient investment to maintain the desired level of reliability and to avoid excessive demand curtailment. To avoid this, capacity markets provide existing and new capacity providers, including demand response and interconnectors, with the opportunity to earn additional revenues, where these are necessary, to justify market entry and/or to prevent exit from the market.

For this purpose, the SEM capacity market is a competitive auction-based mechanism where the lowest-cost capacity is most likely to be successful. To date, ten capacity auctions have been held, including four T-4 auctions, with auction rounds taking place up to four years in advance (i.e, T-4) of the year for which the capacity is being procured. The most recently held capacity auction was the T-4 auction for the 2025/26 capacity year. The SEM Committee recently consulted on 2026/27 T-4 Capacity Auction Parameters and published its decision last month.[4]

The CRM seeks to identify the economically efficient combination of quantity and price of capacity. At a high level, these are determined as follows:

- The target volume of capacity is determined by the SEM Committee in advance of an auction. The SEM Committee sets this volume of capacity based on future capacity requirements in the SEM. The capacity requirement is defined in de-rated terms.
- Most capacity providers that are successful in the capacity auction receive the same auction clearing price for their de-rated capacity. In a competitive market, the price of capacity should converge, over time, to the marginal cost of providing new capacity in the market. This price is defined within the capacity market regime as the Net CoNE rate.

Net CoNE and the BNE

The Net CoNE rate is calculated by subtracting the level of revenue that the best new entrant (BNE) can expect to recover from wholesale markets (inframarginal rents) and from system services from the gross annualised cost of providing capacity (Gross CoNE) in a given year.

The BNE's Net CoNE rate is set in advance of a capacity auction by the SEM Committee and is used to calibrate the auction price caps which exist within the market, as well as the demand curve that is used for the purpose of capacity auctions. Specifically, the BNE estimate contributes to setting the New Capacity Investment Rate Threshold, the Auction Price Cap, and the Existing Capacity Price Cap for each Capacity Auction.

The build-up of the Net CoNE rate that was used for the T-4 2024-25 capacity auction is illustrated in Table 2.1.

Table 2.1: Gross and Net CoNE, €/kW de-rated nominal prices.

€/kW-year (de-rated)	Build-up of Net CoNE
Gross CoNE	112.3
Inframarginal rent	-4
DS3 income	-16.1
Net CoNE	**92.3**

Source: SEM Committee (SEM-21-059 and SEM-18-156).

[3] Hogan, W., (2005), On an "energy only" electricity market design for resource adequacy. Working Paper, September 23, 2005.

[4] SEM Committee, 2022, 2026/27 T-4 Capacity Auction Parameters & Annual Run Hour Limited Plant De-Rating Factor, decision paper, 11 August 2022.

This report sets out our analysis in support of an update to the BNE and its Net CoNE for the T-4 auction for 2026/27.

Reference technologies

The BNE reference technologies are stylised new entrant units with the potential to provide marginal units of capacity in the CRM. They will reflect the technologies which are likely to be in demand and profitable in the period considered by this study. Hence, we note important policy developments and their implications for technology demand, profitability and, hence, new entry.

This study takes place at time of substantial changes in the SEM with the Irish Government, through its Climate Action Plan 2021 (CAP), is seeking to increase the share of electricity demand generated from renewable energy sources (RES) by up to 80% by 2030, halve its emissions by 2030, and reach Net Zero emissions no later than 2050. Similarly, the United Kingdom (UK) Government has legislated to achieve Net Zero emissions by 2050.

The policies of both countries are characterised by the expansion of power generation from RES. In Ireland, the ambition is to have 7GW of offshore wind and 5.5GW of solar by 2030. In the UK, there is ambition to deliver up to 50GW of offshore wind by 2030 and up to 70GW of solar by 2035, some of which would be expected to be located in Northern Ireland. These targets vastly increase the flexibility requirements of the SEM power system, creating additional revenue opportunities for thermal generation technologies and energy storage systems. The increased requirements for flexible technologies may lead to higher volume requirements from some system services, with the potential for higher prices and thereby higher DS3 income for the BNE. At the same time, however, higher volumes of RES will lead to lower operating hours for thermal generation technologies, impacting on energy market revenues. These factors are explored through this report.

There are concerns about the security of supply in the context of Ireland's and Northern Ireland's decarbonisation targets for 2030. In recognition of this, CRU has set a target of 2,000MW of new, flexible gas-fired generation coming online by 2030 in Ireland.[5]

The security of supply concerns are exacerbated by the invasion of Ukraine by Russia which has disrupted the global energy sector. While the focus of this report is the 2026/27 capacity year and beyond, the effects of these events on the future gas prices, as well as the cost of electricity generation technologies, are significant and may endure for years to come. In particular, these factors create uncertainty around equipment costs for all technologies and operating strategy of gas-fired units which impact on their revenue potential.

[5] CRU (2021) Security of Supply Note. Available at cru.ie.

3. SELECTING REFERENCE TECHNOLOGIES

The first step in the BNE process is the identification of reference technologies which have the potential to provide resource adequacy benefits. Broadly, the reference technologies should feature technologies in which rational, private investors in the SEM would be likely to invest.

3.1. Introduction

The starting point for our technology selection process is to develop a long list of options capturing all available technology options which might reasonably be considered as candidate plants for a capacity auction. These options are:

- aggregated generating units (AGUs);
- battery energy storage systems (BESS);
- compressed air energy storage (CAES);
- demand side units (DSUs);
- flywheels;
- interconnectors;
- pumped storage; and
- specific types of fossil-fuel generation:
    - combined cycle gas turbines (CCGT);
    - open cycle gas turbines (OCGT); and
    - reciprocating engines.

To establish a short list, we considered ACER's requirements[6] from its methodology for calculating the cost of new entry. Article 10 of this methodology defines reference technologies as a concept. Item 4, provided in Box 3.1, contains the criteria for consideration as a reference technology.

[6] Found at: https://acer.europa.eu/sites/default/files/documents/Decisions_annex/ACER%20Decision%2023-2020%20on%20VOLL%20CONE%20RS%20-%20Annex%20I.pdf

Box 3.1: ACER requirements

Each reference technology shall meet the following two cumulative criteria:

1. standard technology. A reference technology shall be standard. To identify whether a given candidate technology is standard, the entity calculating CoNE shall demonstrate that:

    i) reliable and generic cost information is available for the cost components defined in Article 13;

    ii) the costs of building and operating units of the technology shall be of the same order of magnitude from one project to another; and

    iii) development of the technology is not significantly bound by technical constraints. Technologies with limited individual capacity which can be aggregated in homogeneous clusters shall be considered as standard if reliable data is available to characterise these clusters. Reliable data may consist of cluster capacity, cluster activation price or generation costs and economic and/or technical activation constraints representative of the cluster;

2. potential new entry. A reference technology shall have potential for new entry. To demonstrate that the candidate technology is representative of possible capacity additions in the coming years, the entity calculating CoNE shall demonstrate that:

    i) capacity representing this technology has been developed in the recent years, is in process of development or is planned for development for the considered timeframe; and

    ii) future development of this technology is allowed and is not significantly hampered by the national and European regulatory framework.

Source: ACER

Each of the options is considered with reference to these requirements.

3.2. Aggregated Generating Units

According to the SEMO definition, an Aggregated Generator is:

> *A collection of Generators located at different Generation Sites each with a capacity of no greater than 10MW and which together comprise an Aggregated Generating Unit within the meaning of the applicable Grid Code.*

The generators that can be part of an AGU are not specified by type or technology. Reliable and generic cost information therefore cannot be established, and we do not consider AGUs to be a reference technology, as defined by Article 10.

3.3. Battery Energy Storage Systems

BESS can provide a range of services in the power system, include short-term frequency response to balance supply and demand, local storage for managing critical peak demand, and filling in the ‘peaks’ and ‘troughs’ in the variable output of some renewable energy sources (RES). Up until this point, BESS operators in the SEM have tended to target revenues from system services and therefore chosen relatively small energy storage volumes (i.e., ≤2 hours). However, this is likely to change in the future, with longer duration BESS entering the market in anticipation of revenue opportunities in the wholesale market created by the increasing volume of RES. This trend is currently being observed in England where a number of larger schemes have been consented. For example, InterGen has a Section 36 consent (under the Electricity Act 1989) for the Gateway Energy Centre in Essex[7]. Within the Section 36 consent, one of the development options includes a 320 MW / 640 MWh BESS in conjunction with a CCGT unit and one or more OCGT units. Of note, the 320 MW / 640 MWh BESS awarded a 15-year contract in the 2022 T-4 GB Capacity Market auction, with the first delivery year commencing on 1 October 2025[8].

---

[7] https://www.gov.uk/government/publications/gateway-energy-centre-variation-to-section-36-consent-electricity-act-1989

[8] https://www.intergen.com/news-insights/categories/news/intergen-secures-capacity-market-agreement-for-world-leading-gateway-battery-project/

For this report we consider a 100 MW/200 MWh plant deploying lithium-ion batteries.

3.4. Demand side units

Like AGUs, DSUs involve the aggregation of multiple demand sites capable of providing demand reductions in response to dispatch instructions from the system operator. Each individual site should contribute no greater than 10MW of such responses.

DSUs have been active in the CRM since it was established, most recently comprising 9% of new capacity in the 2025/26 T-4 auction. In this sense, DSUs have the potential for new entry and are likely to be attractive to rational investors. However, DSUs tend to consist of multiple technologies which may include backup generation and varying forms of load curtailment. For load curtailment, the cost of providing a response is generally thought of as the opportunity cost for that demand site forgoing the consumption of energy. This opportunity can vary from close to zero for some uses, up to prices approaching the value of lost load depending on the nature of energy use.[9] Hence, the costs associated with demand response from DSUs are highly variable and do not meet the requirement for reliable and generic cost information. CoNE studies in other European electricity markets provide precedent for this position.[10]

3.5. Compressed air energy storage

CAES uses underground caverns to store compressed air. Salt caverns formed in salt basins can be used for storage. There are onshore and offshore salt basins in Larne, Northern Ireland. Gaelectric submitted planning permission for 330MW of 6-hour CAES in Larne in 2015. The project was awarded an EU grant of €90 million. However, Gaelectric went into liquidation and the planning application was withdrawn in 2017. The project would have required the development of three 230,000 cubic-metre salt caverns approximately 1.5 km below ground level to store compressed air and provide between six and eight hours of energy. Given the lack of commercial application, and the fact that the cost and capacity would be site-specific, we do not consider this as a standard technology according to the ACER requirements, and therefore is not considered further.

3.6. Flywheels

Flywheels have extensive commercial experience in uninterruptible power supply (UPS) applications. However, the capacity is small, and the operational duration is limited (to minutes), and so we do not consider this as standard technology according to the ACER requirements.

3.7. Interconnectors

Interconnectors are not a generation technology as such, but a means of transferring power from one system to another. Capacity additions are typically infrequent, 'lumpy', and involve uncertainty regarding when they enter the market. These characteristics make interconnectors an impractical candidate for providing the marginal unit of capacity in the CRM. Furthermore, the cost and volume of power that an interconnector can provide at any time depends on the supply-demand conditions in the neighbouring market. On this basis, we do not consider

[9] The variability of industry-specific value can be seen in CEPA, 2018, Study on the estimation of the value of lost load of electricity supply in Europe, For the Agency for the Cooperation of Energy Regulators. Available at europa.eu

[10] See:

- Fichtner, 2020, Cost of Capacity for Calibration of the Belgian Capacity Remuneration Mechanism (CRM): *"There is no such thing as a "standard demand-side resource" that could be used for the cost estimation to identify Gross CONE.".* Available at elia.be.
- Ramboll, 2021, Survey on the cost of entering electricity market in Finland – cost of new energy (CONE): *"Some uncertainties for DSM still occur to as a standard technology"; "Industrial power consumption is not acceptable as standard technology."* Available at energiavirasto.fi.

interconnectors as a standard technology according to the ACER requirements and therefore provide no further consideration.

3.8. Pumped storage

There is limited recent experience with pumped storage development in Ireland or Northern Ireland. Turlough Hill, a 4 x 73 MW station became fully operational in 1974. Planning permission for Silvermines (360 MW) is due to be submitted in Q1, 2023. The cost of pumped storage cannot be considered standard, as it will inevitably depend on the chosen site. We do not consider this as standard technology according to the ACER requirements and is therefore not considered further.

3.9. Fossil fuel generation

3.9.1. Technologies

The technologies considered are:

- combined cycle gas turbines ("CCGT");
- open (or simple) cycle gas turbines ("OCGT"); and
- reciprocating engines ("engines").

3.9.2. Fuel choice

Because of the requirements of the Secondary Fuel Obligation in Ireland and Fuel Switching Agreements in Northern Ireland, the capability to fire distillate fuel is considered a minimum requirement. Therefore, the following configurations are included in a long list:

- Dual fuel;
    - main fuel: natural gas (NG); and
    - back-up fuel: distillate fuel oil (DFO);
- DFO only.

3.9.3. Regulatory requirements

Emission Limits

The Industrial Emissions Directive (IED)[11] came into force on 7 January 2011. The IED lays down rules on integrated pollution prevention and control arising from industrial activities.

Chapter III of the IED provides special provisions related to large combustion plants, where the total rated thermal input is equal to or greater than 50 MW, irrespective of the type of fuel used. Under Chapter III, Article 30 relates to 'Emissions limit values' (ELVs) which are upper limits which must not be exceeded.

For 'New Plant' (i.e., those granted a permit after 7 January 2013), the ELVs are specified at Annex V, Part 2. For new gas turbines (including OCGT and CCGT) and gas engines, the ELVs are shown below.[12]

[11] Directive 2010/75/EU on industrial emissions (integrated pollution prevention and control).

[12] The ELVs are calculated at a temperature of 273.15 K, a pressure of 101.3 kPa, after correction for the water vapour content of the waste gases and at a standardised O2 of 15% for gas turbines and gas engines.

Table 3.1: 'Emission limit values' (EVLs) for new gas turbines and engines

Generator Type	Fuel Type	NOx ELV (mg/Nm^3)
Gas Turbines	Gas	**50**
	Light and Middle Distillates as Liquid Fuels	**50**
Gas Engines	Gas	75
	Light and Middle Distillates as Liquid Fuels	N/A

However, gas turbines and gas engines for emergency use that operate less than 500 operating hours per year are not covered by the ELVs above. In these cases, the operators shall record the used operating hours.

Annual Run Hour Limits (ARHL)

One of the conditions discussed in the IED is in relation to Annual Run Hour Limits (ARHL). The SEM Committee in its Information Note SEM-21-107[13] states that *"with regards to licencing processes in Ireland, technologies other than a Combined Cycle Gas Turbine (CCGT) can be compliant with the BAT [Best Available Technique] Conclusions for LCP [Large Combustion Plants] without being subject to an ARHL of 1,500 hours."* ARHL is not applied to relevant BNE candidates in Ireland, reflecting our understanding of how the BAT provisions are interpreted by the Irish Environmental Protection Agency. ARHLs are applied to relevant BNE candidates in Northern Ireland, reflecting our understanding of how the BAT provisions are interpreted by the Northern Ireland Environment Agency.

Energy Efficiency Levels

The BAT conclusions also present BAT Associated Energy Efficiency Levels (BAT-AEELs). [14]

For 'New' gas turbines (including OCGT and CCGT) and gas engines, the BAT-AEELs are shown below.

Table 3.2: BAT associated energy efficiency levels for gas turbines and engines

Generator Type	Fuel Type	BAT-AEEL (%)	
		Open cycle	Combined cycle
Gas Turbines	Gas	36-41.5	57-60.5
	Liquid	> 33	
Gas Engines	Gas	39.5-44	No BAT-AEEL
	Liquid	41.5-44.5	>48

[13] Information Note regarding the Application of Annual Run Hour Limits SEM-21-107; (https://www.semcommittee.com/sites/semc/files/media-files/SEM-21-107%20Info%20Note%20re%20the%20Application%20of%20Annual%20Run%20Hour%20Limits.pdf)

Table 3.3: BAT associated emission levels for gas turbines and engines

Generator Type	Fuel Type	NOx BAT-AEL (mg/Nm^3) [15]
Gas Turbines	Gas	For OCGT: Yearly Average: 15 – 35 Daily Average: 25 – 50 For CCGT: Yearly Average: 10 – 30 Daily Average: 15 – 40
Gas Engines	Gas	Yearly Average: 20 – 75 Daily Average: 55 – 85

CO_2 Emissions Limits

Regulation EU/2019/943 on the internal market for electricity came into force on 4 July 2019. Its purpose was to establish the fundamental principles for well-functioning, integrated electricity markets. Article 22 of the Regulation outlines 'Design principles for capacity mechanisms.' Paragraph 4 is provided in Box 3.2.

Box 3.2: Design principles for capacity mechanisms – Article 22, paragraph 4.

Capacity mechanisms shall incorporate the following requirements regarding CO2 emission limits:

(a) from 4 July 2019 at the latest, generation capacity that started commercial production on or after that date and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity shall not be committed or to receive payments or commitments for future payments under a capacity mechanism;

(b) from 1 July 2025 at the latest, generation capacity that started commercial production before 4 July 2019 and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity and more than 350 kg CO2 of fossil fuel origin on average per year per installed kWh shall not be committed or receive payments or commitments for future payments under a capacity mechanism.

That is, for generating units that start commercial operation on or after 4th July 2019 to be allowed to receive payments under a capacity mechanism, the Fossil Fuel Emissions (FFE) must be no greater than 550 g CO_2/kWh of net electrical power generation.

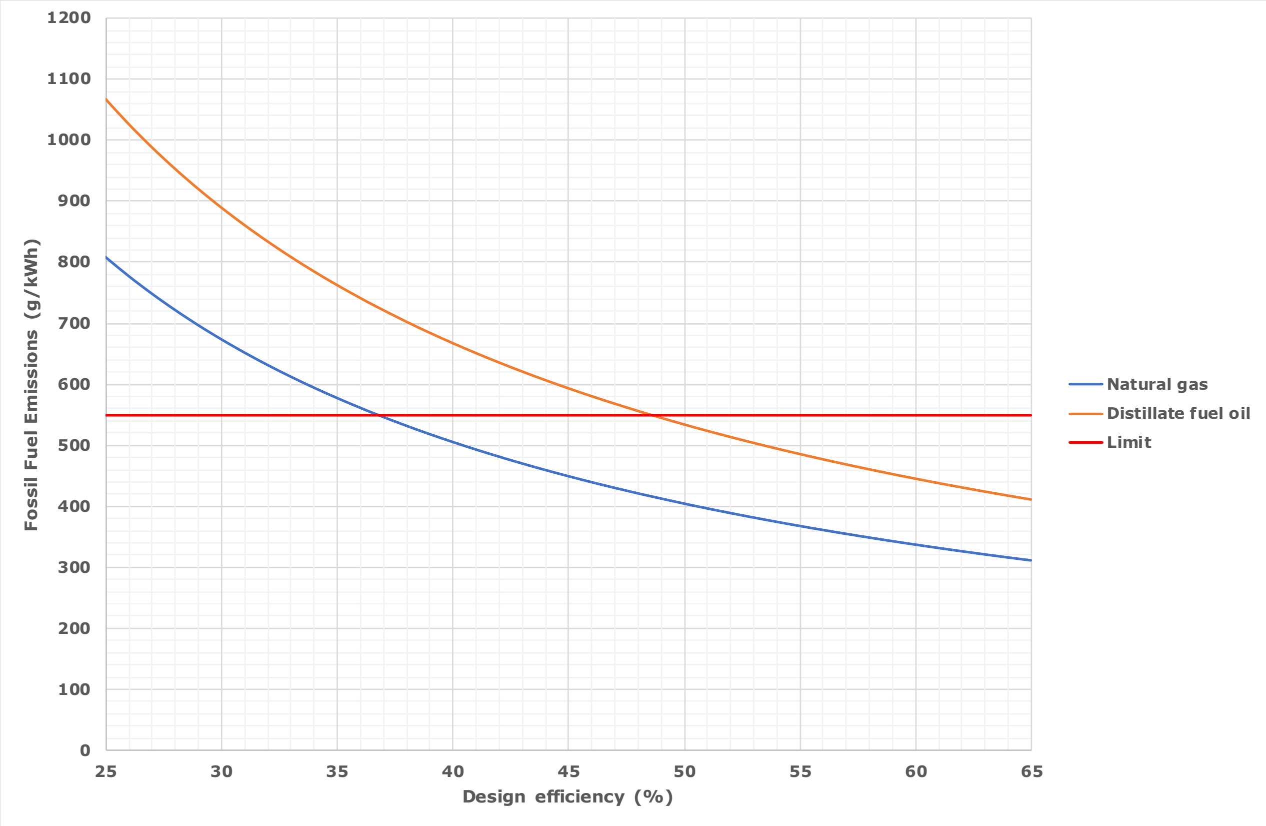
The limit of 48.5% on oil is above the BAT-AEEL for OCGT (33%), and for engines (41.5%-44.5%), and is therefore taken as the minimum required efficiency for OCGT and engines.

Figure 3.1 shows the effect of design efficiency on FFE, using standard emission factors of 53.1 kg CO_2/MJ for natural gas, and 74.1 kg CO_2/MJ for DFO. To achieve the FFE limit, the minimum efficiency required is 36.7% when firing on natural gas and 48.5% when firing on distillate fuel oil.

The limit of 36.7% on gas is within the BAT-AEEL range for OCGT (36%-41.5%), and below the BAT-AEEL range for engines (39.5%-44%). The minimum efficiency is therefore taken as 36.7% for OCGT (CO_2 emissions limit) and 39.5% for engines (BAT-AEEL).

The limit of 48.5% on oil is above the BAT-AEEL for OCGT (33%), and for engines (41.5%-44.5%), and is therefore taken as the minimum required efficiency for OCGT and engines.

Figure 3.1: Effect of design efficiency on Fossil Fuel Emissions for natural gas and distillate fuel oil



3.9.4. Combined cycle gas turbine plant (CCGT)

Table 3.4 shows the CCGT generators in SEM, as given in EirGrid's All-Island Capacity Statement 2021-2030. The recent plants have been based on F class gas turbine technology.

Table 3.4: All-Island CCGT generation

Station	Capacity MW	Commercial operating date	Gas turbine model	Gas turbine class
Aghada	431	2010	Alstom GT26	F
Dublin Bay (Ringsend)	415	2002	Alstom GT26	F
Great Island	464	2015	Mitsubishi 701F	F
Huntstown I	337	2002	Siemens SGT5-2000E	E
Huntstown II	408	2007	Mitsubishi 701F	F
Poolbeg	2 x 234	1994-1998	Siemens SGT5-2000E	E
Tynagh	389	2006	GE 901F	F
Whitegate	444	2010	GE 901F	F

Table 3.5 shows net power and efficiency ratings under ISO standard conditions[16] for large F and H/J class gas turbines in combined cycle mode for one gas turbine and one steam turbine). All the H/J class exceed 500 MW, which we consider to be too high a capacity for the SEM market considering the likely operational regime in a high-RES system and that such a unit could become the largest single infeed, which would be undesirable. Even F class unit can exceed 500 MW in CCGT, with efficiency at or above 60%.

Table 3.5: F and H/J class gas turbines CCGT ISO rating

Model	Class	Net CCGT power output MW	Net LHV Efficiency %
Ansaldo GT36-S6	H	520	62.3
Ansaldo GT36-S5	H	760	62.6
Ansaldo GT26	F	540	61.0
Ansaldo V9.3A	**F**	**495**	**60.0**
GE 9HA.01	H	680	63.7
GE 9HA.02	H	838	64.1
GE 9F.04	**F**	**443**	**60.2**
MHI 701JAC (2015)	J	840	>64.0
MHI 701JAC (2018	J	650	>64.0
MHI 701F	F	566	62.0
Siemens SGT5-8000H	H	660	61.2
Siemens SGT5-9000HL	H	860	>63
Siemens SGT5-4000F	**F**	**475**	**59.7**

We consider that a CCGT unit of less than 500MW would be most suitable for entry into the SEM and therefore continue our analysis on the basis of a single shaft CCGT of approximately 450-500MW of rated capacity.

3.9.5. Open cycle gas turbines

Gas turbines are based on the Brayton cycle available as industrial type and aero-derivative type.

Aero-derivatives generally operate with high pressure ratios, are more efficient, have shorter start-up times and are more suitable for cycling than industrial type. However, they have a higher capital cost and are limited in capacity, the largest rated aero derivative being GE's LMS100, with an ISO rating of 113 MW. Industrial gas turbines are available up to a capacity of more than 500 MW.

As explained above, the FFE limit requires a minimum efficiency of 48.5% when operating on DFO. Gas turbines cannot achieve this, so only dual-fuel engines are considered, with DFO being used only in an emergency. The 36.7% requirement when firing natural gas is achievable by many gas turbine models.

Based on the regulatory requirements given in Section 3.9.3, operation is limited as follow:

1. Operate no more than 1500 per year
2. Maximum operation on emergency fuel (DFO) 500 hours
3. Yearly average NOx 50 mg/nm³

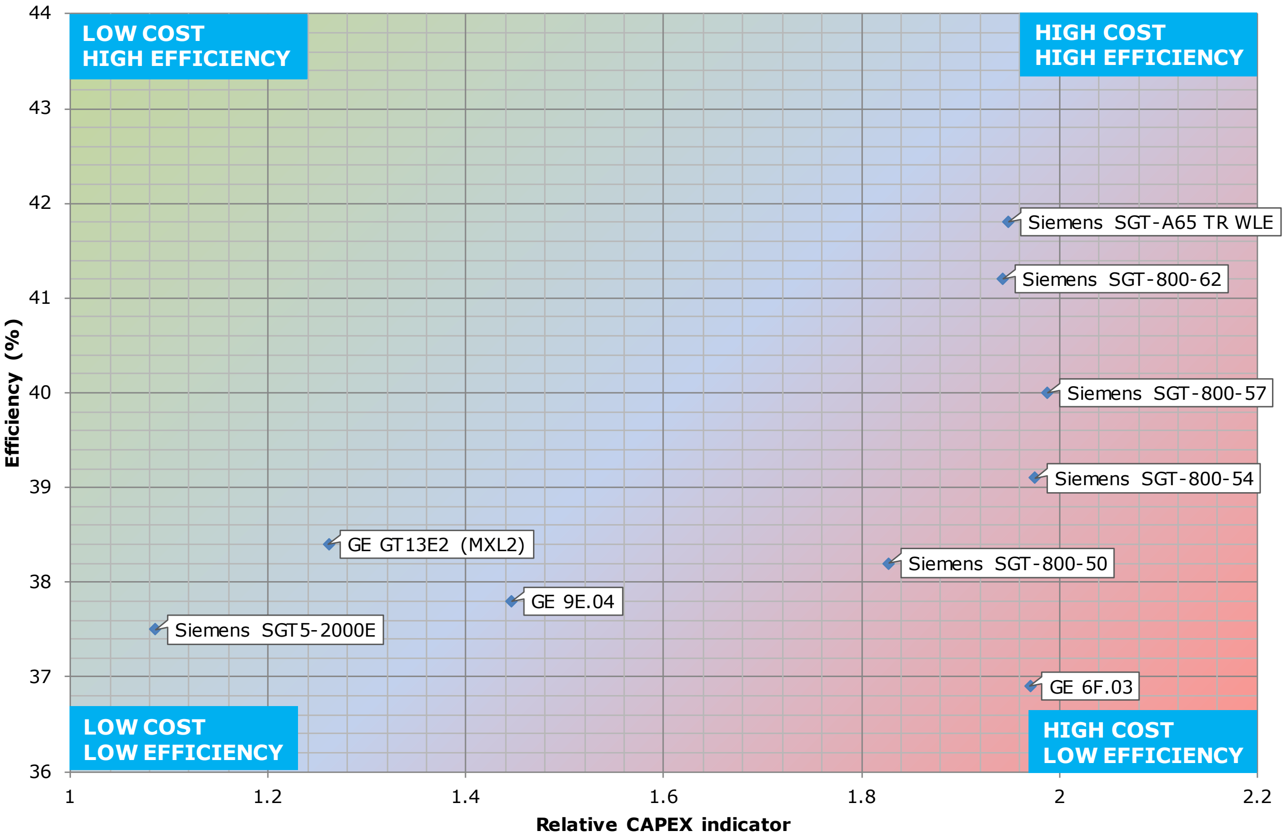
[16] As per ISO standard 3977-2: 1997 (Gas turbines — Procurement — Part 2: Standard reference conditions and ratings) the standard conditions are an ambient temperature of 15°C, relative humidity of 60% and ambient pressure consistent with being at sea level.

4. Minimum efficiency operating on gas 36.7%
5. Water injection not required

Figure 3.2 shows the efficiency and relative cost for GTs (50 MW – 200 MW) which meet the required minimum efficiency. The values are based on the basic gas turbine costs from the latest version of GT PRO. The reference cost is that of the largest generator.

Based on this the SGT5-2000E was used to represent the open cycle plant.

Figure 3.2: ISO efficiency versus relative cost factor for OCGT (50 MW – 200 MW), efficiency ≥ 36.7%



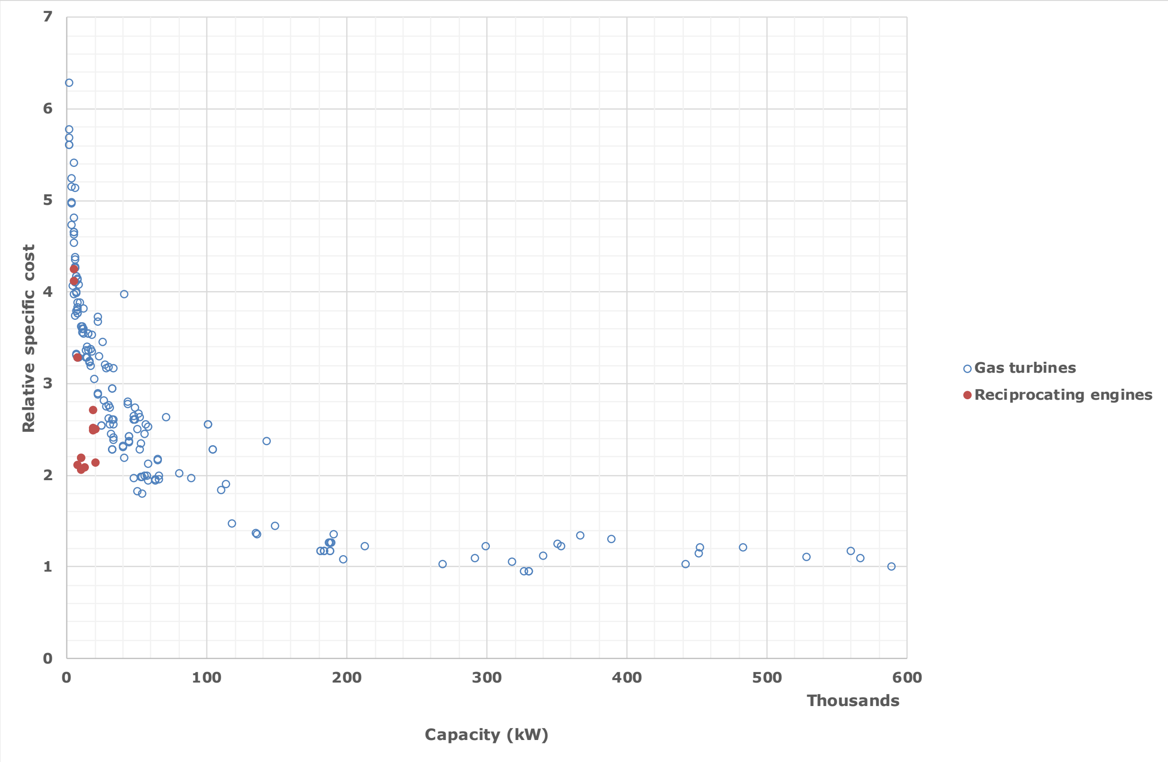
3.9.6. Reciprocating engines

In previous BNE reports, reciprocating engines were discounted because of their high specific cost (i.e. the EPC cost per unit power output - €/MW). The generator size of up to 200 MW, and the low annual operating hours favoured larger plant. The specific cost relative to the specific cost of the largest capacity plant was calculated. Figure 3.3 shows the effect of generator capacity on this relative specific cost. The data is based on the reference costs given in the latest version of GT PRO. Above 200 MW there is little variation in the specific cost. Below 200 MW the specific cost rises logarithmically.

However, engines have higher ramp rates and lower start times than gas turbines, so can provide faster response. Engines are also more efficient than gas turbines which may become significant extending operating hours from 500 hours to 1500 hours per year.

Engines suffer little power degradation and lower efficiency degradation than turbines.

Figure 3.3: Relative specific cost of gas turbines and reciprocating engines over full capacity range



Engines can be categorised as follows:

- **Gas engines.** These use spark ignition, based on the Otto cycle, using a spark plug to ignite a pressurized air-fuel mixture.
- **Diesel engines.** These use compression-ignition, based on the Diesel cycle, where air is compressed to a temperature higher than the auto-ignition temperature before fuel is injected and ignites in the cylinder.
- **Dual fuel engines.** These can operate on gas or liquid. When operating on gas, the spark plug is replaced by a pilot fuel flame. The requirement for pilot fuel reduces the efficiency of dual fuel engines.

Because of the requirement to burn DFO, gas engines are not considered further.

The FFE limit requires a minimum efficiency of 48.5% when operating on DFO. This is very challenging and limits the choice of engines, so we therefore only consider dual-fuel engines, DFO being used only in an emergency. The 36.7% requirement when firing natural gas is readily achievable.

Based on the regulatory requirements given in Section 3.9.3, operation is limited as follow:

- Operating no more than 1,500 hours per year.
- Maximum operation on emergency fuel (DFO) 500 hours.
- Yearly average NOx 75mg/nm³
- Minimum efficiency operating on gas 36.7%.

Candidate engines include:

Manufacturer	Model	Generator output MW
MAN Energy	51/60 DF	20.4
Wärtsillä	W50 DF	17.6

3.10. Capacity auction history

There have been ten auctions to date for which we summarise the results for awarded capacity in Table 3.6 and Figure 3.4. The auctions have been dominated by gas-fired generation, reflecting the historical composition of the market. Awards to steam plant have steadily reduced or time. DSU, pumped storage and interconnectors has been reasonably steady, whilst awards to wind generation and other storage (BESS) has increased in recent years.

Table 3.6: Capacity auction results – awarded capacity (all)

	Auction									
Generator type	**18/19 T-1**	**19/20 T-1**	**20/21 T-1**	**21/22 T-2**	**22/23 T-1**	**22/23 T-4**	**23/24 T-4**	**24/25 T-3**	**24/25 T-4**	**25/26 T-4**
Autoproducer	105	105	115	115	-	105	115	-	-	115
Demand Side Unit	548	426	415	455	116	415	505	64	420	394
Gas Turbine	4,486	4,779	4,537	4,607	346	4,789	5,154	1,167	4,783	4,930
Hydro	200	200	192	192	6	190	191	-	196	196
Interconnector	451	451	419	419	17	404	423	-	421	421
Other Storage	-	-	6	6	54	81	61	144	22	120
Pumped Hydro Storage	228	228	221	221	-	209	228	-	203	203
Steam Turbine	1,737	1,612	1,280	1,063	556	860	600	96	65	65
Steam Turbine - IED	-	439	397	397	-	418	-	-	-	-
Wind	19	26	24	37	26	56	45	-	58	40
Total	**7,774**	**8,266**	**7,606**	**7,512**	**1,121**	**7,529**	**7,322**	**1,471**	**6,168**	**6,484**

Figure 3.4: Capacity auction results – awarded capacity (all)

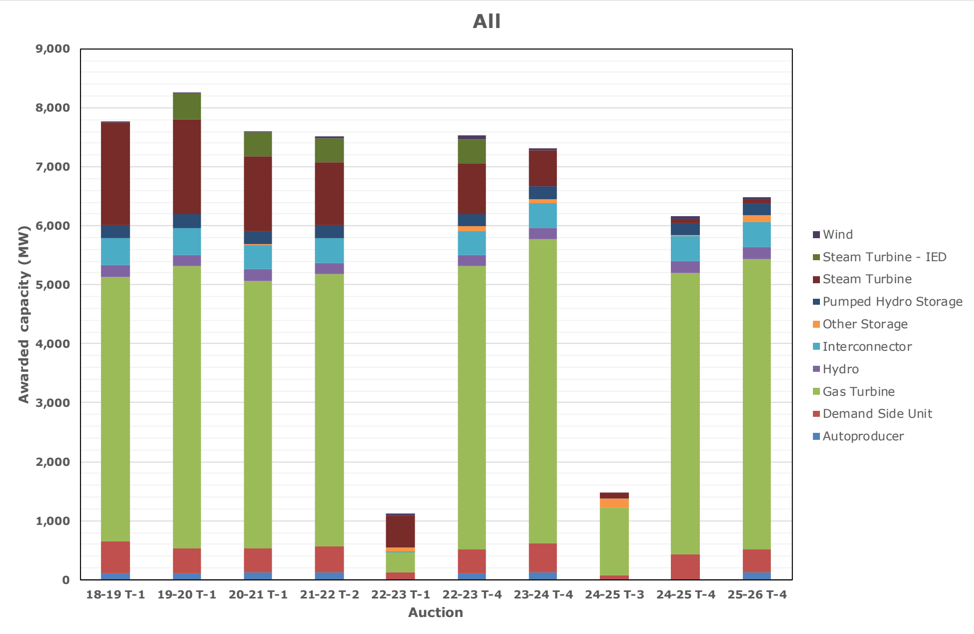


Figure 3.5 shows a summary of results for new awarded capacity. In earlier years, up to the 2021/2022 T-2 auction, new capacity awarded was dominated by DSUs. Other storage (batteries) began to appear in the 2022/2023 T-1 auction, but since the 2023/2024 T-4 auction new capacity awarded has been dominated by gas turbines, with some DSU and BESS.

Figure 3.5: Capacity auction results – awarded capacity (new)

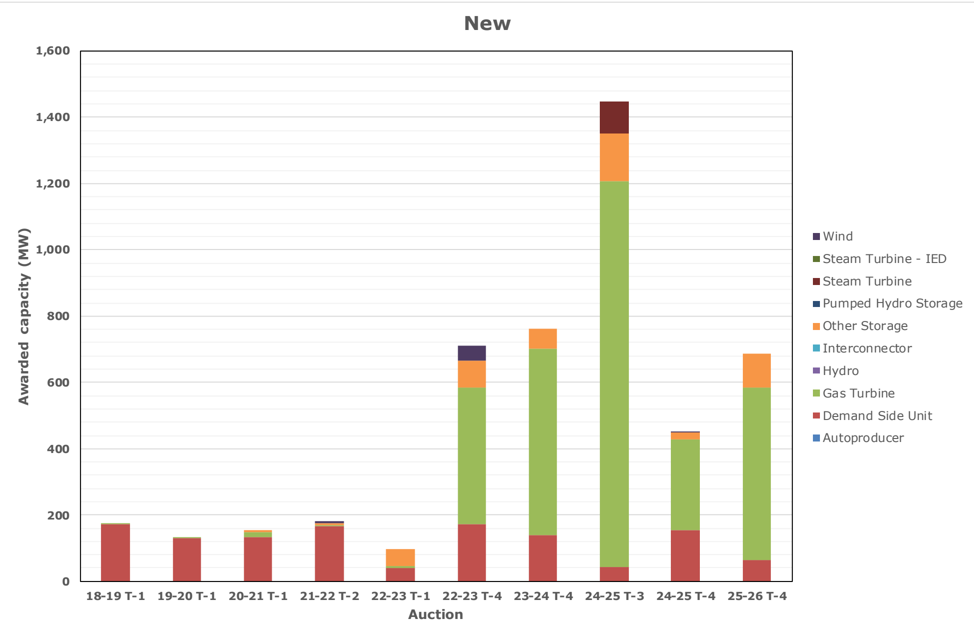
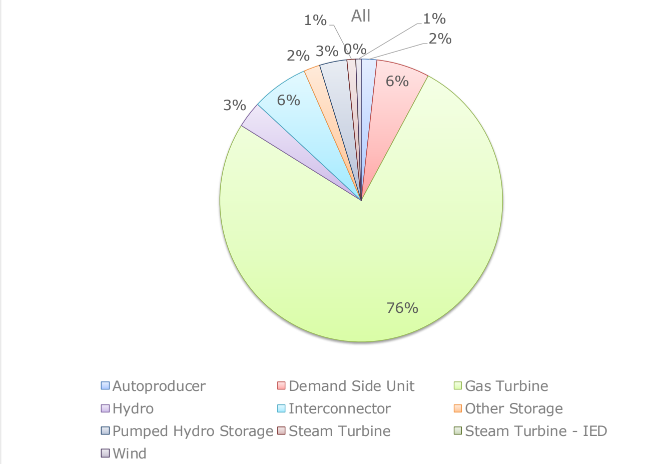


Figure 3.6 shows the results of the 2025/2026 T-4 auction. Here, new capacity awarded is spilt between gas turbines (521 MW, 76%), other storage – batteries (103 MW, 15%) and DSU (64 MW, 9%).

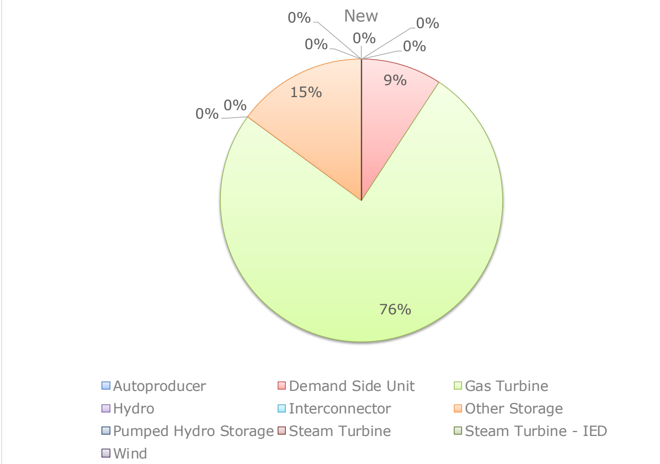
Although the “Gas Turbine” category includes reciprocating engines, we understand that most of this is capacity is gas turbines.

Figure 3.6: Capacity auction results – awarded capacity 2025-2026 T-4

All generation



New generation



3.11. Selected plant

Based on the above criteria and evidence, the following plants are further considered:

Table 3.7: Short list of BNE reference technologies

Technology type	Unit size
CCGT (single shaft)	Approximately 450 MW - 500 MW
Open cycle gas turbine	Approximately 200 MW
Reciprocating engines	Approximately 200 MW
BESS	100 MW/200 MWh

3.11.1. CCGT thermodynamic modelling and performance

The following technical assumptions were made:

- Single shaft.
- Standard triple pressure reheat cycle.
- Air cooled condenser.
- Annual average ambient conditions:
  - Dry bulb temperature 10°C
  - Relative humidity 80%
  - Ambient pressure 1013 mbar
- Transmission voltage of 110kV for Northern Ireland and 220kV for Ireland.
- Distillate storage of 5 days
- No fogging or inlet air evaporative cooling employed.
- No Selective Catalytic Reduction for NOx control.

- Water storage, for providing water injection, not required for NOx control.[17]
- No black-start capability.
- Average degradation
    - 2.8% on power output
    - 1.5% on efficiency
- Flexibility:
    - Minimum gas turbine load 40%
    - Hot start time: 30 minutes
    - CCGT ramp rate 5%/min

The as-new net power output and efficiency of the power plant was calculated from models generated using the latest version of GT PRO. The table below shows net power and efficiency ratings under ISO standard conditions for large F and H/J class gas turbines in combined cycle mode for one gas turbine and one steam turbine). All the H/J class exceed 500 MW, which we consider to be too high a capacity for the SEM market considering the likely operational regime in a high-RES system and that such a unit could become the largest single infeed, which would be undesirable. Even F class unit can exceed 500 MW in CCGT, with efficiency at or above 60%.

Table 3.5 showed three candidate turbines with CCGT output lower than 500 MW:

- AE 94.3A
- GE 9F.04
- Siemens SGT5-4000F

To calculate indicative technical parameters, we modelled the thermodynamic performance of each turbine. The weighted averages from this analysis are shown below.

Table 3.8: Technical parameters for CCGT unit

Parameter	Unit	Value
Output new	MW	470.0
Output degraded	MW	456.6
Efficiency new	%	58.57
Efficiency degraded	%	57.69
Fuel input new	LHV MJ/s	802.1
Fuel input degraded	LHV MJ/s	791.5
CO_2 emitted new	g/kWh	344.8
CO_2 emitted degraded	g/kWh	350.1

[17] Operating on gas, the gas turbine can satisfy the BAT requirements for NOx emissions; the BAT provisions do not provide emissions limits for gas turbines operating on distillate oil. Directive 2010/75/EU on industrial emissions (IED) states a limit of 50 mg/nm³ when a unit is firing on oil, but that this limit does not apply for emergency use of less than 500 hours per year. We assume that there will be an annual limit operating on distillate oil of 500 hours per year, only in an emergency, and so water injection is not required.

3.11.2. OCGT modelling and performance

The following technical assumptions were made:

- Average ambient conditions for two coldest months:
  - Dry bulb temperature 5.5°C
  - Relative humidity 80%
  - Ambient pressure 1013 mbar
- Transmission voltage of 110kV for Northern Ireland and 220kV for Ireland.
- Distillate storage of 3 days
- Water injection, and therefore water storage is not required for NOx control (as for CCGT).
- No fogging or inlet air evaporative cooling employed.
- No Selective Catalytic Reduction for NOx control.
- No black-start capability.
- Average degradation
  - 2.6% on power output
  - 1.6% on efficiency
- Flexibility:
  - Minimum gas turbine load 40%
  - Hot start time: 20 minutes
  - Ramp rate 8%/min

The as-new net power output and efficiency of the power plant was calculated from models generated using the latest version of GT PRO, based on the SGT5-2000E gas turbine. Indicative performance is shown below.

Table 3.9: Technical parameters for OCGT unit

Parameter	Unit	Value
Output new	MW	205.0
Output degraded	MW	199.7
Efficiency new	%	37.28
Efficiency degraded	%	36.7
Fuel input new	LHV MJ/s	550.1
Fuel input degraded	LHV MJ/s	544.5
CO_2 emitted new	g/kWh	541.7
CO_2 emitted degraded	g/kWh	550.0

3.11.3. Reciprocating engine modelling and performance

The following technical assumptions were made:

- Average ambient conditions for two coldest months:
    - Dry bulb temperature 5.5°C
    - Relative humidity 80%
    - Ambient pressure 1013 mbar
- Transmission voltage of 110kV for Northern Ireland and 220kV for Ireland.
- Distillate storage of 3 days
- Water injection, and therefore water storage is not required for NOx control (as for CCGT).
- No fogging or inlet air evaporative cooling employed.
- No Selective Catalytic Reduction for NOx control.
- No black-start capability.
- Average degradation
    - 0% on power output
    - 1.2% on efficiency
- Flexibility:
    - Minimum engine load 10%
    - Hot start time: 2 minutes
    - Ramp rate 100%/min

The as-new net power output and efficiency of the power plant was calculated from models generated using the latest version of GT PRO. Indicative performance is shown below:

Table 3.10: Technical parameters for reciprocating engines

Parameter	Unit	Value
Output new	MW	200.3
Output degraded	MW	200.3
Efficiency new	%	48.8
Efficiency degraded	%	48.3
Fuel input new	LHV MJ/s	410.1
Fuel input degraded	LHV MJ/s	415.1
CO_2 emitted new	g/kWh	413.9
CO_2 emitted degraded	g/kWh	418.1

3.11.4. BESS

BESS is based on power output of 100 MW with 2 hours of storage capacity, i.e. 200 MWh. The plant is based on prefabricated modules. BESS operate at DC, and therefore require an inverter system to convert to AC current for participation in the wholesale energy market.

The plant would comprise:

- Batteries, housed in enclosures, including:
    - Control & protection systems;

    - Power conversion systems and associated transformers;
    - Temperature regulation systems
- Banking station comprising:
    - Main step-up transformers
    - Switchgear and cabling
- All other associated works:
    - Civil works
    - C&I
    - Testing and commissioning.

3.12. Derating factors

The Net CoNE metric applied in the CRM is expressed as the costs of the BNE per unit of de-rated capacity. The de-rating factors which we apply in this report reflect the decision of the SEM Committee on 2026/27 T-4 Capacity Auction Parameters[18], leading to:

- De-Rating Curves, defining Rating Factors by unit Initial Capacity and by Technology Class.
- Annual Run Hour Limits (ARHL) de-rating factors to apply to New Capacity with ARHLs less than or equal to 1,500 hours (in Northern Ireland only – see section 3.9.3).

The SEM Committee decided to 'freeze' the De-Rating Curves from the 2025/26 T-4 auction[19] such that the same values apply for 2026/27 except for the additional derating factors for New Capacity with ARHLs and for energy/time limited DSUs.

Reflecting these decisions, the derating factors which we apply to the short-listed BNE technologies are set out in Table 3.11. We apply ARHL de-rating factors for OCGT and reciprocating engines locating in Northern Ireland only.

Table 3.11: Capacity de-rating factors used in this analysis

Parameters	CCGT		OCGT		Engines		BESS	
	IE	NI	IE	NI	IE	NI	IE	NI
Technology de-rating factor	0.825	0.825	0.883	0.883	0.882	0.882	0.362	0.362
ARHL de-rating factor	N/A	N/A	N/A	0.430	N/A	0.430	N/A	N/A

[18] https://www.semcommittee.com/sites/semc/files/media-files/T-4_2026_27_Parameters_Decision_Paper.pdf

[19] https://www.sem-o.com/documents/general-publications/Initial-Auction-Information-Pack_IAIP2526T-4.pdf

4. CAPITAL FIXED COSTS

In this section, we focus on capital fixed costs i.e., the up-front investment in a generation plant. The main cost item is the EPC contract, though there are a number of other costs which we discuss in turn below.

4.1. EPC CONTRACT

The overarching approach to estimation remains consistent with previous BNE studies, albeit with updated information.

The shortlisted plants were modelled using the latest updated version of the proprietary thermodynamic modelling programme GT PRO and its associated cost estimation program, PEACE, supplied under license by Thermoflow, Inc. In addition, the reference plant was modelled to provide further calibration of the plant cost estimations.

GT PRO is a top-down design program used to fix the design of the gas turbine-based power plant using a set of key parameters, including:

- ambient site conditions;
- number and model of GT;
- fuel (gas and / or liquid);
- cycle type (number of pressures, reheat / non-reheat, condensing, non-condensing);
- configuration (single- or multi-shaft, and number of steam turbines);
- HV connection arrangement and voltage;
- steam cycle parameters; and,
- cooling system type.

The outputs include:

- detailed heat and mass balance, including:
  - gas turbine performance and exhaust conditions;
  - HRSG steam conditions;
  - steam turbine performance and steam conditions;
  - cooling system parameters;
- auxiliary loads and transformer losses;
- equipment sizing and simple specifications;
- simple plot plan; and
- EPC cost estimate.

GT PRO/PEACE develops “reference costs” based on the GT model and plant design. Cost multipliers can be selected based on the project country. These multipliers cover Specialized Equipment (GTs, STs etc), Other Equipment (tanks, pumps etc), and Labour and Commodity cost for installation of BOP equipment. As in previous BNE studies, we applied default cost multipliers in GT PRO/PEACE.

The PEACE prices reference date is February 2022. It is recognized that there is much volatility in world markets. Many factors will affect the cost including labour and commodity costs, market confidence, and demand. A detailed analysis is beyond the scope of this report, however, to allow for changes in 2022, reference has been made to the change in producer prices during 2022, and an 8.4% increase in the PEACE price has been included. This was based on a comparison of the producer prices index for the Euro area[20] between February and June (the last available index at the time of initial reporting). Comparisons have also been made to generic costs published by DECC & BEIS in the UK, and the US EIA.

For the CCGT plant, costs were calculated for all of the plant modelled as described in Section 3.11.1 and a weighted average calculated.

The price is based on full turnkey EPC price. This includes all equipment, delivery, erection, commissioning and testing including high voltage (HV) transformers, cabling and switchgear, and where required, gas receiving and conditioning equipment.

Costs are summarised in Table 4.1 and are based on HV connection of 220 kV for Ireland, and 110 kV for Northern Ireland, the lower voltage resulting in lower cost for Northern Ireland. Specific cost shown is based on the as-new power output. Construction period is from Notice to Proceed to Commercial Operating Date.

Table 4.1: EPC Contract Price

Technology type	EPC cost (€ million)		Specific cost (€/kW) (€/kWh for BESS)		Construction period (months)
	Ireland	Northern Ireland	Ireland	Northern Ireland	
CCGT	315.90	313.60	673	668	36
OCGT	79.10	77.80	398	392	24
Engines	173.10	167.20	864	835	18
BESS	69.00	66.60	345	333	18

Source: CEPA / Ramboll.

4.2. Site procurement costs

We consider that agricultural land values are a suitable proxy in the calculation of site procurement costs. This assumption has been used in previous BNE studies and has publicly available information to develop a suitable estimate.

Data has been sourced from the Irish Farmer's Journal, reflecting average agricultural land values in 2021[21]. According to our estimates site procurement costs are relatively similar across Ireland and Northern Ireland, with the latter being around 13% more expensive after currency conversion.

We note that previous BNE studies have applied a significantly higher per unit cost for the land required for the power plant than indicated by this data, although the source has been used for considering price changes against an original estimate. The land estimates had been informed by broker estimates for the 2009 BNE, with a specific site in Belfast West used in previous BNE studies.

We have applied a 100% uplift on average per acre costs to reflect that not all agricultural land will be suitable for constructing the generation plant, and our expectation that industrial land is likely to be higher cost than agricultural land.

We use an exchange rate based on the spot rate as of 17 August 2022. The estimate is sourced from Bloomberg.

[20] Available at https://tradingeconomics.com/euro-area/producer-prices

[21] Available here: https://www.rte.ie/news/business/2022/0316/1286705-land-values-up-by-a-third-in-2-years-farmers-journal/#:~:text=At%20%E2%82%AC11%2C966%20on%20average,33%25%2C%20the%20study%20concludes.

Table 4.2: Agricultural land value on a per unit basis

	Ireland	Northern Ireland
Prior to uplift		
Price / acre – reported currency	€17,949	£17,166
Exchange rate: GBP:EUR	n/a	1.1782
Price / acre - Euros	€17,949	€20,225
With uplift		
Uplift	100%	100%
Price / acre – Euros, post uplift	€35,898	€40,450

Source: Irish Farmers Journal estimate, Bloomberg.

We multiply this per acre cost by the required area assumed for each generation technology to obtain estimated site procurement costs.

Table 4.3: Assessment of land costs

Technology type	Required area (acres)	Estimated site cost (€ million)	
		Ireland	Northern Ireland
CCGT	13.59	0.49	0.55
OCGT	4.94	0.18	0.20
Engines	5.44	0.20	0.22
BESS	4.94	0.18	0.20

Source: Irish Farmers Journal estimate, CEPA / Ramboll.

4.3. Connection costs

4.3.1. Electrical

Connection costs are a considerable factor in the overall cost a new site faces. Our estimates for electrical connection costs use a single cost across technologies for each jurisdiction. We have taken the relevant TSO price lists for unit costs[22] and used our judgement on the quantities of equipment for the connection. The basis for our calculation is shown below.

[22] EirGrid, 2022 Standard Transmission Charges; NIE Networks, Transmission Charging Statement.

Table 4.4: Estimates for electrical connection costs

Item	Unit cost	Quantity	Total cost
Ireland (€m)			
New 220kV line bay in existing 220kV outdoor station, double busbar	1.35	2	2.70
220kV SC Tower 600mm2 ASCR 80 degrees C with earthwire (<10km)	0.81	5	4.05
All / Total			**6.75**
Northern Ireland (£m)			
110kV double circuit OHL (10km)	0.66	5	3.30
Double busbar bay	1.24	2	2.48
All / Total			**5.78**

Source: CEPA/ Ramboll analysis of TSO price lists.

We apply our given exchange rate for GBP/ EUR to establish total costs for electrical connections in Northern Ireland. This converts the £5.78m figure to €6.81m.

Table 4.5: Electrical Connection Cost Estimates

Technology type	Electrical connection cost (€ million)	
	Ireland	Northern Ireland
CCGT	6.75	6.81
OCGT	6.75	6.81
Engines	6.75	6.81
BESS	6.75	6.81

Source: CEPA / Ramboll.

4.3.2. Gas and water connections

We have estimated the costs associated with securing a water supply and a connection to the gas network (where applicable).

For the water connection, this includes the total cost of an installed 1km pipeline, 100 mm in diameter (150 mm for CCGT). This cost was estimated using GT MASTER/PEACE.

For the gas connection, we included the total cost of an installed 2km pipeline, 150 mm in diameter for engines, 200 mm for OCGT and 150 mm for CCGT. This cost was estimated using GT MASTER/PEACE.

Table 4.6: Water Connection & Gas Connection Cost Estimates

Technology type	Connection costs (€ million)	
	Water	Gas
CCGT	0.97	4.80
OCGT	0.67	3.80
Engines	0.67	3.00
BESS	0.67	0.00

Source: CEPA / Ramboll.

4.4. Owners' contingency

Owner's contingency covers such things as project delays due to force majeure events and the resulting lost revenue, additional civil works costs due to unexpected sub-terrain, and claims relating to interface problems. We have retained the assumptions from multiple previous BNE studies. Based on our experience, 5.0% of the value of the EPC cost has been attributed to owner's contingency (in addition to any embedded contingency within the EPC price). This is a well-accepted benchmark and is consistent with the estimate used in multiple previous BNE studies.

Table 4.7: Owner's Contingency

Technology type	Owner's contingency (€ million)	
	Ireland	Northern Ireland
CCGT	15.80	15.68
OCGT	3.96	3.89
Engines	8.66	8.36
BESS	3.13	3.08

Source: CEPA / Ramboll.

4.5. Financing fees

Our financing costs have been estimated as a proportion (2.0%) of EPC costs based on our experience. This is consistent with the estimate used in multiple previous BNE studies.

Table 4.8: Financing Costs

Technology type	Financing costs (€ million)	
	Ireland	Northern Ireland
CCGT	6.32	6.27
OCGT	1.58	1.56
Engines	3.46	3.34
BESS	1.25	1.23

Source: CEPA / Ramboll.

4.6. Construction insurance

Our construction insurance costs have been estimated as a proportion (0.9%) of EPC costs based on our experience. This is consistent with the estimate used in multiple previous BNE studies.

Table 4.9: Construction Insurance

Technology type	Construction insurance (€ million)	
	Ireland	Northern Ireland
CCGT	2.84	2.82
OCGT	0.71	0.70

Technology type	Construction insurance (€ million)	
	Ireland	Northern Ireland
Engines	1.56	1.50
BESS	0.56	0.55

Source: CEPA / Ramboll.

4.7. Initial fuel working capital

Our study requires an estimate of the initial fuel costs required to comply with regulatory policies, for example the secondary fuel obligation in Ireland. For gas plant this requires three days of storage for plants operating less than 2630 hours per year, and five days of storage for plants operating more than 2630 hours per year. The storage is based on the rated capacity of the plant on its primary fuel.

The storage requirement is shown in Table 4.10. We have based the distillate oil price on a spot basis (as of 17 August 2022) of $96.72 per barrel. We have used equivalent daily exchange rates to convert into euros per million litres[23]. There is zero cost for BESS, as for them there is no fuel requirement.

Table 4.10: Distillate Oil Storage Requirement

Technology type	Distillate oil storage requirement (million litres)	Cost per litre (€)	Initial fuel working capital cost (€ million)
CCGT	9.5	0.61	5.76
OCGT	3.7	0.61	2.24
Engines	2.9	0.61	1.76
BESS	-	-	-

Source: Bloomberg, CEPA / Ramboll.

4.8. Other non-EPC costs

In keeping with the presentation of “Other non-EPC costs” from previous BNE reports, the reasoning behind this grouping of costs is as follows. While the costs specified above are relatively easily determinable, many of the costs under “Other non-EPC costs” are difficult to benchmark against other projects due to varying definitions and groupings of costs. The types of costs covered by “Other non-EPC costs” include Environmental Impact Assessment (EIA), legal, owner’s general and administration, owner’s engineer, start-up utilities, commissioning, O&M mobilisation and spare parts.

We retain the assumptions used in the previous BNE report based upon cost benchmarking with the percentage of EPC cost allocated to other non-EPC costs being 9.0% (7.0% for BESS). We consider, based on our judgement, that this reflects a suitable benchmark for those costs.

[23] We use a conversion of 158.99 litres to one barrel of oil. We use an exchange rate of 1.1829 to convert from USD to GBP, based on Bloomberg estimates on 17 August 2022.

Table 4.11: Other non-EPC Costs

Technology type	% of EPC cost for other non-EPC	Other non-EPC costs (€ million)	
		Ireland	Northern Ireland
CCGT	9.0%	28.43	28.22
OCGT	9.0%	7.12	7.00
Engines	9.0%	15.58	15.05
BESS	7.0%	4.38	4.31

Source: CEPA / Ramboll.

4.9. Interest During Construction (IDC)

Our IDC calculations of the interest on the loan amount are based on the notional gearing rate prior to the plant earning revenues, not including any premium on the cost of debt during the construction phase (see Section 6 for further details on our cost of capital estimate). The construction phase is modelled using three years for the CCGT, and two years for the other generation technologies.

Table 4.12: Interest during construction costs

Technology type	IDC costs (€ million)	
	Ireland	Northern Ireland
CCGT	7.27	6.60
OCGT	2.00	1.48
Engines	4.06	2.95
BESS	1.52	1.13

Source: CEPA / Ramboll.

4.10. Participation and Accession Fees

Before beginning operation, the BNE will have to pay a market accession fee that covers the costs of assessing its application, as well as a participation fee in order to register and become a participant as part of its unit application.

Table 4.13: Market accession and participation fees

Type of charge	Current charge
Market Accession fee	€1,044
Participation fee	€2,610

Source: SEMO – MO Tariffs & Charges and Imperfections Charge, 2021-22.

4.11. Summary

Table 4.14: Summary of capital fixed costs (€m)

Technology type	CCGT		OCGT		Engines		BESS	
	Ireland	N.I	Ireland	N.I	Ireland	N.I	Ireland	N.I
EPC contract	315.90	313.60	79.10	77.80	173.10	167.20	62.60	61.60
Site procurement cost	0.49	0.55	0.18	0.20	0.20	0.22	0.18	0.20
Electrical connection costs	6.75	6.81	6.75	6.81	6.75	6.81	6.75	6.81
Water connection	0.97	0.97	0.67	0.67	0.67	0.67	0.67	0.67
Gas connection	4.80	4.80	3.80	3.80	3.00	3.00	-	-
Owners contingency	15.80	15.68	3.96	3.89	8.66	8.36	3.13	3.08
Financing	6.32	6.27	1.58	1.56	3.46	3.34	1.25	1.23
Construction insurance	2.84	2.82	0.71	0.70	1.56	1.50	0.56	0.55
Initial Fuel working capital	5.76	5.76	2.24	2.24	1.76	1.76	-	-
Other non-EPC costs	28.43	28.22	7.12	7.00	15.58	15.05	4.38	4.31
Interest During Construction	7.25	6.54	1.99	1.47	4.05	2.94	1.51	1.11
Accession fee[24]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Participation fee[25]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total, €m	**395.31**	**392.02**	**108.10**	**106.14**	**218.78**	**210.85**	**81.03**	**79.58**

[24] Figures are less than 0.01 when rounded to two decimal places.

[25] Figures are less than 0.01 when rounded to two decimal places.

5. RECURRING (FIXED) COSTS

In this section, we refer to annually recurring fixed costs. We assume that these are incurred each and every year of the generation plant's operations.

5.1. FIXED MARKET OPERATOR CHARGES

As the administrator of the market, SEMO levies charges to recover its own costs, as well as allowed market related costs. The only charge relevant to our BNE calculation is the Market Operator Charge, which is detailed in the table below. This is €70 per MW, based on the latest available evidence.

Table 5.1: Market Operator charges

Technology type	Fixed market operator charge (€ million)
CCGT	0.03
OCGT	0.01
Engines	0.01
BESS	0.01

Source: SEMO – MO Tariffs & Charges and Imperfections, 2021/22, CEPA / Ramboll.

5.2. ELECTRICITY NETWORK CHARGES

Our estimations for Electricity Transmission Use of System (TUoS) charges vary according to a technology's capacity, load factor, as well as a country-wide average of generation location based per MWh charges, which are listed in EirGrid and SONI's 2021/2022 Statement of Charges for Ireland and Northern Ireland, respectively.

Table 5.2: Electricity Transmission Charges

Currency	Electricity TUoS charges (cost per MW per year)	
	Ireland	Northern Ireland
National	€6,295.29	£4,236.82
Euros	€6,295.29	€4,991.82

Source: Eirgrid, SONI, CEPA / Ramboll.

We multiply those figures by plant capacity to obtain the overall electricity transmission network charges.

Table 5.3: Electricity Transmission Charges

Technology type	Electricity TUoS charges (€ million)	
	Ireland	Northern Ireland
CCGT	2.96	1.99
OCGT	1.25	0.84
Engines	1.26	0.85
BESS	0.63	0.42

Source: Eirgrid, SONI, CEPA / Ramboll.

5.3. Gas network charges

Gas consuming units must pay transmission charges to receive the gas which they wish to consume for power generation. These charges are defined in terms of entry and exit capacity to the gas network and can be procured through products ranging from daily to annual. The BNE's choice is relevant for Gross CoNE since procurement on a long-term basis (e.g., annual products) leads to a fixed cost which is 'sunk' on an operational timescale, whereas short-term procurement is a variable cost which should be reflected in a unit's offers in the day ahead market. The costs of short-term capacity should be recoverable through wholesale revenues.

For Ireland, we assume that gas-fired BNE units expected to provide peaking capacity (i.e., OCGT and reciprocating engines) would procure daily products and hence that their fixed costs for the purpose of Gross CoNE are zero. In contrast, CCGT units tend to operate for more hours and would find it cheaper to buy annual products. We assume that these units would procure annual entry and exit capacity to cover 65%, consistent with the modelling which informed our assumptions for infra-marginal rent.[26] We use Moffat as the relevant entry point for marginal generation, with a domestic exit charge. The charges were drawn from the CRU's published document, "Gas Networks Ireland Transmission Tariffs and Allowed Revenue 2022/23." The peak day MWh entry charge is €356.82 and €501.68 for exit.

For NI, there is less flexibility in contracting approach. While there are daily products for entry capacity there is no daily product for exit capacity. Hence, we assume that peaking units would procure some annual exit capacity only. We assume that OCGT and reciprocating engines would procure exit capacity to cover 15% of the unit's rated capacity. We make the same assumption as for Ireland in the case of CCGT, i.e., annual entry and exit capacity to cover 65% of rated capacity.

The NI system uses postalised tariffs, with identical entry and exit capacity charges on an annual basis. Charges were drawn from GMO's 21/22 gas year "NI Forecast Postalised System Transmission Tariffs." We have taken the value of £0.36220 per kWh per day booked as the forecast tariffs for 2025/26. This is the latest available estimate provided in the publication. We use the exchange rate conversion set out in previous steps i.e., using the spot exchange rate as of 17 August 2022.

Table 5.4: Gas transportation charges

Technology type	Gas Transportation Charges (€ million)	
	Ireland	Northern Ireland
CCGT	10.75	10.68
OCGT	0.00	0.81
Engines	0.00	0.63
BESS	0	0

Source: GMO Northern Ireland, CEPA / Ramboll.

5.4. Fixed operating maintenance

Maintenance costs cover the day-to-day operations and maintenance of the power station, including scheduled maintenance of the main generating plant, covered by a service agreement. The day-to-day maintenance includes all routine preventative maintenance in accordance with the OEM's recommendations for the main generating plant, all other balance of plant ("BOP"), ancillary equipment, buildings and grounds.

[26] This modelling was undertaken by the UR primarily for the purpose of assessing applications for Unit Specific Price Caps. Its use in this report is discussed in section 7.1

The costs are based on baseload operation for the CCGT plant and 1500 hours per year for OCGT. Personnel costs are shown in Table 5.5.

We assess BESS personnel costs later, based on the format of available information.

Table 5.5: Personnel Costs

Technology type	Personnel costs (€ million)
CCGT	3.65
OCGT	0.90
Engines	0.90

Source: CEPA / Ramboll.

Fixed O&M (FOM) costs are shown in Table 5.6. We calculate this as a proportion of the EPC on an annual basis. For 2-hour BESS, we assume 1.8% of the EPC price per year for FOM, including personnel costs.

Table 5.6: Fixed O&M Costs

Technology type	Fixed O&M €/kW	Fixed O&M cost (€ million)	Specific FOM (% of EPC)	
			Ireland	Northern Ireland
CCGT	9.0	4.23	1.34	1.35
OCGT	4.5	0.92	1.17	1.19
Engines	18.0	3.61	2.08	2.16
BESS	15.0	1.50	1.80	1.80

Source: CEPA / Ramboll.

5.5. Insurance

Our insurance estimate is based on a percentage of EPC costs and is based on past experience. We have assumed insurance costs are 0.6% of EPC costs. This is consistent with estimates in multiple previous BNE studies.

Table 5.7: Insurance Costs

Technology type	Insurance costs (€ million)	
	Ireland	Northern Ireland
CCGT	1.90	1.88
OCGT	0.47	0.47
Engines	1.04	1.00
BESS	0.41	0.40

Source: CEPA / Ramboll.

5.6. Business rates

Annual business rates are the commercial taxes paid to local authorities in Ireland, and regional authorities in Northern Ireland.

The annual cost of business rates in Ireland has been calculated by multiplying the value of the plant by a county-specific valuation multiplier known as the 'Annual Rate on Valuation'. By averaging these county-level valuation multiplier, we have estimated a multiplier rate on valuation of 74. We also retain the assumption from our previous BNE study that plants are valued at €115/MW. We have uplifted this for inflation since September 2015 (the date of the CEPA report) to August 2022[27].

Our annual business rate estimations for Northern Ireland utilise valuations for different types of electricity generators set out in "Valuation (Electricity) Order (Northern Ireland) 2003" and non-domestic rate poundages for 2022-23. Our estimations for annual business rates for all reference technologies are presented below in Table 5.8.

Table 5.8: Annual business rates

Technology type	Annual business rates (€ million)	
	Ireland	Northern Ireland
CCGT	4.55	1.50
OCGT	1.92	0.97
Engines	1.94	0.98
BESS	0.97	0.49

Source: Valuation Office Ireland, Valuation Electricity Order Northern Ireland 2003, CEPA / Ramboll.

[27] Using Irish CPI inflation (all items). The uplift factor is 1.1312.

5.7. Summary

Table 5.9: Summary of recurring costs (€m/ year)

Technology type	CCGT		OCGT		Engines		BESS	
	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland
Fixed market operator charges	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01
Electricity network charges	2.96	1.99	1.25	0.84	1.26	0.85	0.63	0.42
Gas network charges	10.75	10.68	0.00	0.81	0.00	0.63	0.00	0.00
Personnel costs	3.65	3.65	0.90	0.90	0.90	0.90	-	-
Fixed O&M costs	4.23	4.23	0.92	0.92	3.61	3.61	1.50	1.50
Insurance	1.90	1.88	0.47	0.47	1.04	1.00	0.38	0.37
Business rates	4.55	1.50	1.92	0.97	1.94	0.98	0.97	0.49
Total, €m/yr	**28.06**	**23.97**	**5.48**	**4.93**	**8.76**	**7.99**	**3.48**	**2.79**

6. COST OF CAPITAL

The calculation of Net CoNE involves the estimation of a Weighted Average Cost of Capital (WACC), weighting together debt and equity costs using the following formula:

$$WACC = (E / (D + E)) * rE + (D / (D + E)) * rD$$

- rE is the **cost of equity**
- rD is the **cost of debt**
- E and D are the total values of equity and debt, respectively

E and D are used to determine the level of **gearing,** which is used in the WACC formula to derive the relative weights between the costs of equity and debt finance.

Cost of equity

We estimate the cost of equity following a CAPM approach. CAPM is a model from financial economics, commonly used for regulatory determinations of the cost of equity.

We derive our CAPM cost of equity estimates using the following formula which relates the cost of equity to a 'risk-free rate', the expected return on a market-wide portfolio of investments and a business-specific measure of investors' exposure to systematic risk (beta). The post-tax cost of equity is calculated:

$$rE = rf + \beta E * (TMR - rf)$$

- rf is the **risk-free rate,** which is the theoretical return an investor would expect to earn on a riskless investment.
- βE or **equity beta** is a business-specific measure of an investor's exposure to systemic risk that cannot be reduced by holding a diverse portfolio of investments.
- TMR is the **total market return,** representing the expected return on a market-wide portfolio of investments.

We note that some CAPM formulations simplify the calculation shown above with an 'equity risk premium' that captures the difference between the 'total market return' and the 'risk-free rate'. As per regulatory precedent in the UK and Ireland, we focus on a formulation with an explicit total market return value as a primary approach, with an additive risk-free rate plus equity risk premium approach considered as an alternative.

The CAPM formulation shown above uses an equity beta, which should be tailored to the notional gearing level assumed for the WACC to account for how the required equity return grows with greater proportions of debt in the business. To account for that gearing effect on the equity beta, we focus our analysis on the **asset beta**. We have not included a **debt beta** in our calculations.

We convert the post-tax cost of equity into a pre-tax equivalent by adjusting for the relevant corporate tax rate.

Cost of debt

The cost of debt is the return required to cover efficient debt interest costs and fees. We estimate a cost of debt that covers raising new investment for the BNE, i.e. assuming no embedded debt. We focus on the 'all in' cost of debt values (i.e., risk-free rate plus debt premium), as incorporated in relevant debt benchmark indices.

6.1. KEY PRINCIPLES

This section sets out the high-level principles we followed to guide our methodology and choice of data inputs used to estimate the WACC. Later sections go into further detail for each WACC parameter, but these overarching principles inform the approach throughout.

Entity of focus

We focus on a typical generation technology that we assume represents the Best New Entrant. This entity is assumed to finance itself efficiently, raising debt at prevailing market rates, maintaining gearing at the level assumed in the WACC, and paying any dividends to shareholders in a financially sustainable manner.

We calculate two separate WACCs; one in relation to a Northern Ireland location and the second located in the Republic of Ireland.

Regional focus

We focus on a sterling-based investment in Northern Ireland first. We do not include any specific Northern Ireland premium, as per the current approach of the Utility Regulator (UR) in estimating the cost of capital[28]. The relevant estimates will be shown under a 'UK' heading in the remainder of the section.

In a currency union, such as the Eurozone, investing in an Irish generation technology *should* be similar to investing in a comparably risky investment in any other part of the Eurozone (subject to the impact of different regulatory frameworks and expectations of demand and cost variability). This supports using Eurozone-wide evidence, rather than limiting our analysis to Ireland-specific data.

Data selection

The parameters estimated in the following sections draw on a wide range of evidence following the above principles. This naturally leads to a range of plausible values, as is common in cost of capital estimations.

We include a data cut-off, as of 31st July 2022. We would expect to update these values ahead of the final report.

Form of WACC estimate

The BNE calculation requires use of a nominal pre-tax WACC. This is the basis that we present our estimates on in this paper.

Use of regulatory precedent

The use of regulatory precedent needs to be done in a way that is consistent with the nature of the exercise here. Regulatory precedent on network price controls may carry little direct relevance on certain parameters, such as the asset beta, but principles may be used indirectly. The derivation of a nominal return differs to the real cost of capital estimates typically derived for regulated networks in Ireland and NI Ireland.

Point estimate versus range

In this paper, we use point estimates for WACC parameters, which flow through into a point estimate for the overall cost of capital. We have adopted our view on the best estimate of the WACC, rather than construct a range. This does not mean uncertainty does not exist.

Indexation / updating

Our approach aims to create a replicable approach that can be updated mechanistically for subsequent iterations of the BNE calculation. As such, we have centred our estimates on a singular methodology, though we recognise that broader data may be applicable and inform an overall judgement. This is especially true at a time where there is significant interest rate, commodity market and macroeconomic volatility.

[28] For example, in the GD23 price controls.

6.2. PARAMETER ESTIMATION

In this sub-section, we provide estimates of individual WACC parameters. We go through the methodology for each parameter, before setting out of estimates for each of the two jurisdictions.

6.2.1. Risk-free rate

Methodology

Yields on sovereign bonds (i.e., debt issued by national governments) are often used by economic regulators to assess the risk-free rate in support of cost of capital determinations. We focus our analysis on sovereign debt yields and regulatory precedent to assess the risk-free rate.

For the Northern Ireland estimate, we use UK nominal gilts. For the Republic of Ireland estimate, we use German nominal gilts as a proxy for the Eurozone risk-free rate asset, with Germany having a AAA credit rating from S&P.

We use the 10-year tenor as a liquid, long-term proxy for the risk-free rate.

We are trying to estimate a current estimate of the risk-free rate. We are trying to strike a balance between ensuring our estimate reflects current market conditions, whilst limiting the volatility that arises from using shorter-term data. We consider that use of a one-month average is most appropriate at present, in light of market volatility and recognising that current estimates may change materially.

Market evidence

The table below shows the data resulting from the above methodology.

Table 6.1: Yields on relevant market benchmarks – risk-free rate

	Eurozone	UK
Nominal yields, 1-month average	1.14%	2.06%

Source: Bloomberg

Estimate – NI

We use an estimate of **2.06%** for the NI risk-free rate.

Estimate - IE

We use an estimate of **1.14%** for the IE risk-free rate.

6.2.2. TMR & ERP

Methodology

In CAPM, the TMR is the expected return for an investor that holds a theoretical ‘market portfolio’ of all assets available in the investible universe. It can be decomposed into the risk-free rate and an ‘equity risk premium’ (ERP) – the additional return over the risk-free rate that the investor expects to earn on the market portfolio of investments.

The relationship between the risk-free rate and ERP have been debated extensively in the context of regulatory cost of capital determinations. A particular point of contention is if the ERP is stable over time (meaning that TMR moves in line with the risk-free rate) or offsets movements in the risk-free rate (meaning that TMR is stable over time). The approaches can be referred to as CAPM-TMR and CAPM-ERP approaches respectively.

Recently, regulators in Ireland and the UK have adopted approaches that assume a relatively stable TMR. However, we note that regulators in other jurisdictions (e.g., Australia) have adopted alternative approaches on both theoretical and empirical grounds, which may be well justified in those circumstances, in particular, where different conclusions and assumptions can be justified from the market evidence.[29] In this paper, we focus on the CAPM-TMR led precedent applied in Ireland and Great Britain.

We utilise precedent for both jurisdictions. This precedent focuses on what is referred to as the 'historic ex-post' approach, using 100+ years of outturn data on market returns - this includes both historic TMR and historic ERP returns. The approaches also include reference to 'historic ex-ante' approaches, namely adjusting those historical returns for one-off events. We consider that assessing real TMR estimates is preferrable to assessing nominal TMR directly, given variability in historic inflation.

Market evidence

To apply our approach we draw upon real TMR estimates, as highlighted above. We start by considering index-linked gilt (ILG) yields i.e., inflation-indexed yields on government debt. We refer to 10yr ILGs, equivalent to the 10yr nominal bonds considered in estimating the risk-free rate.

Table 6.2: Yields on 10yr index-linked gilts

	Eurozone	UK
Real yields, 1m average	-0.95%	-1.61%

Source: Bloomberg. Note: GB real yields use RPI inflation.

We use real TMR estimates from recent regulatory precedent. For the Eurozone estimates, we consider recent Irish precedent on the real TMR.

Table 6.3: Recent Irish regulatory precedent on real TMR

	Lower bound	Upper bound
CRU, PC4 (2017)	6.50%	6.80%
CRU, RC3 (2019)	6.75%	7.80%
CRU, PR5 (2020)	5.70%	6.75%
CRU, Greenlink Interconnector (2021)	6.45%	6.75%

Source: CEPA review of CRU published reports

We consider that the most recent precedent, using a 6.45-6.75% range is representative over the varied precedent that exists. We take a point estimate of 6.60%, the mid-point of this range.

For UK estimates of the real TMR, we use Ofgem's RIIO-ED2 Draft Determinations real (CPIH) TMR mid-point of 6.50%[30]. We use a RPI-CPIH wedge of 0.70%, as currently utilised by Ofgem in its cost of equity estimates. This gives a real (RPI) TMR of 5.76%, which is comparable to real ILG yields.

Table 6.4: Real TMR estimates

	Eurozone	UK
Real TMR	6.60%	5.76%
Real RfR	-0.95%	-1.61%
Implied ERP	7.55%	7.37%

Source: CEPA analysis

We use the implied ERP at this point in time to calculate the nominal TMRs for both jurisdictions. As we have used an equivalent period of data i.e., one-month to end-July 2022, the approach should be internally consistent.

[29] See discussion in CEPA (2021), Relationship between RFR and MRP, prepared for the Australian Energy Regulator (AER).

[30] https://www.ofgem.gov.uk/sites/default/files/2022-06/RIIO-ED2%20Draft%20Determinations%20Finance%20Annex.pdf

Table 6.5: Nominal TMR estimates

	Eurozone	UK
Nominal RfR	1.14%	2.06%
Estimated ERP	7.55%	7.37%
Nominal TMR (implied)	8.69%	9.43%

Source: CEPA analysis

Estimate – NI

We use an estimate of **9.43%** for the nominal TMR for NI.

Estimate - IE

We use an estimate of **8.69%** for the nominal TMR for IE.

6.2.3. Beta

Methodology

The asset beta measures the systematic risk of a company – in this case the BNE – relative to the overall market. No perfect comparator is available for us to include directly. We calculate a set of asset beta estimates using market data for a set of publicly listed comparator companies.

Longlist of comparators

We created a longlist of potential comparators based on two principal sources – Bloomberg benchmark groupings and a brief literature review.

Benchmark groups

We included the constituents of the Bloomberg European Pure-Play Renewable Power Generator Valuation Peers (BIEURPCP Index) and those companies that met the following criteria:

- Bloomberg Eurozone Development Markets (Large, Medium and Small Cap), with BICS Industry Classification of either Renewable Project Developers or Power Generation.

Literature review

We have conducted a literature review of studies on estimating relevant hurdle rates for generation technologies. This includes reports including:

- NERA (2015)
- Noothout (2016)
- Europe Economics (2018)

This gives a list of over 100 comparators.

Shortlist of comparators

We then refined this list down to draw on the most relevant comparators and most robust data sources:

- Refine companies to those domiciled in Europe (source: Bloomberg).
- Refine companies to those which are active in electricity generation (source: interpretation of Bloomberg company descriptions).
- Refine comparator list to those which are pure-play generators (source: interpretation of Bloomberg company descriptions).

- Review of comparators and relevant generation technologies (source: company websites).

Based on this shortlisting process, we had 23 comparators remaining. In reviewing this list, we found that there was very limited coverage of OCGT / CCGT / gas engine technologies. We have therefore added in ENGIE, RWE and EDF to broaden the set of comparators.

The selected 26 comparators are captured below. As acknowledged previously, there will be material differences in risk profile faced by these comparators in relation to each generation technology[31], however we consider that the approach facilitates a market-based approach that has limited directional biases.

Table 6.6: Description of utilised comparators

Name	Description
Orsted	Orsted A/S provides utility services. The Company engages in the development, construction, and operation of offshore wind farms, as well as generates power and heat from power stations. Orsted serves customers worldwide.
EDP Renovaveis SA	EDP Renovaveis SA designs, develops, manages, and operates power plants. The Company generates electricity using renewable energy sources through wind energy. EDP Renovaveis serves customers worldwide.
Acciona Energia Financiacion Filiales SA	Corporacion Acciona Energias Renovables SA, doing business as Acciona Energia, operates as a renewable energy utility. The Company owns and develops renewable energy technologies including onshore wind, solar PV, hydraulic, thermal, biomass, and storage assets. Acciona Energia is vertically integrated across the renewable energy value chain and serves customers worldwide.
ERG SpA	ERG S.p.A. is a producer of energy from renewable sources (wind, solar, hydroelectric and thermoelectric) in Europe, with presence mainly in Italy, France and Germany. The Company via a subsidiary carries out centralized Energy Management activities for all the generation technologies, and the Operations and Maintenance activities for most of its wind farms.
Neoen	Neoen operates as an independent energy company. The Company develops, finances, builds, and manages renewable energy power plants such as solar, wind, and biomass. Neoen serves customers worldwide.
Drax	Drax Group PLC is a renewable energy company engaged in renewable and flexible power generation and sales to business customers. The Company operates a portfolio of biomass, hydro-electric and pumped hydro storage generation assets across the UK and is a large source of renewable electricity. Drax Group also operates a global sustainable biomass supply chain.
Falck Renew N	Falck Renewables SpA produces energy from renewable sources. The Company is creating a portfolio of wind energy projects across Europe, focusing on certain key countries including the UK, Italy, Spain and France.
ENCAVIS AG	Encavis AG provides electricity generation from power plants. The Company produces power from renewable energy sources which includes solar energy plants and wind farms, as well as specializes in the technical operation of solar parks, routine maintenance, monitoring, incident management, and performance analysis. Encavis serves renewable energy sector in Europe.
SCATEC ASA	Scatec ASA operates as an energy company. The Company installs, operates, and maintains solar, hydro, and wind power plants. Scatec serves customers worldwide.
Voltalia SA	Voltalia S.A. produces electricity from alternative sources. The Company uses hydroelectric, wind, and biomass to generate electricity in France, Guyana, and Brazil.
Alerion Cleanpower SpA	Alerion Cleanpower SpA is a renewable energy utility company. The Company's activities include wind, solar, and biomass projects.

[31] We are conscious that our sample includes a large number of Renewable Energy Sources (RES).

Name	Description
CERES Power Holdings	Ceres Power Holdings plc operates as a fuel cell technology and engineering company. The Company generates and distributes energy to businesses, homes, and vehicles. Ceres Power Holdings serves customers globally.
Albioma SA	Albioma SA generates energy from biomass produced by agriculture activities and is agribusiness's energy partner.
Grenergy Renovables SA	Grenergy Renovables, S.A. is a project developer and an Independent Power Producers that generates renewable energy mainly through solar photovoltaic plants. The Company has offices in Western Europe, as well as Central and South America.
PNE AG	PNE AG plans and manages onshore and offshore wind farms. The Company develops, plans, finances, operates, sells and services electricity producing wind farms. PNE serves customers in Europe, Africa, and North America.
ABO Wind AG	ABO Wind AG provides renewable energy services. The Company designs and develops wind energy farms. ABO Wind offers services throughout Europe. ABO Wind offers investors solid investment opportunities in wind energy funds, wind farms, and bio energy projects.
Cloudberry Clean Energy ASA	Cloudberry Clean Energy ASA operates as a renewable energy company. The Company owns, develops, and operates hydropower plants and wind farms. Cloudberry Clean Energy serves customers in Norway and Sweden.
7C Solarparken AG	7C Solarparken AG provides energy solutions. The Company designs, develops, and operates photovoltaic energy systems. 7C Solarparken serves customers in Germany.
Eolus Vind AB	Eolus Vind AB develops and sells wind farms for generating electricity.
Arise AB	Arise AB is an alternative energy company. The Company produces and supplies electricity from wind energy to companies, municipalities, and organizations in Sweden.
Naturel Yenilenebilir Enerji Ticaret AS	Naturel Yenilenebilir Enerji Ticaret AS operates as a renewable energy company. The Company develops, builds, and manages wind, solar, biomass power, and hydroelectric plants. Naturel Yenilenebilir Enerji Ticaret serves customers globally.
Clearvise AG	Clearvise AG produces renewable energy. The Company develops and operates wind energy plants. Clearvise operates wind parks in Germany, Ireland, and France.
Audax Renovables SA	Audax Renovables, S.A. generates electricity. The Company develops and operates wind energy farms, biomass, and other renewable energy projects. Audax Renovables serves customers in America and Europe.
ENGIE	Engie SA offers a full range of electricity, gas and associated energy and environment services throughout the world. The Company produces, trades, transports, stores, and distributes natural gas, and offers energy management and climatic and thermal engineering services.
RWE AG	RWE AG is a globally active energy company. The Company generates and trades electricity. RWE has a capacity of about 10 gigawatts based on renewable sources, as well as gas fleet and an internationally active energy trading business. RWE serves clients in Europe, Asia-Pacific, and the United States.
EDF	Electricite de France (EDF) produces, transmits, distributes, imports and exports electricity. The Company, using nuclear power, coal and gas, provides electricity for French energy consumers.

Source: Bloomberg

There are five companies that we exclude from the above sample; four are due to listing periods that do not cover the full length of our time period under assessment (Acciona, Neoen, ABO Wind and and Cloudberry) one company due to a beta estimate that is abnormally low (Clearvise). This leaves 21 remaining comparators.

Empirical estimation

We calculate daily asset beta estimates using 2yr windows and averaging the beta estimates over a five-year period. We calculate gearing over the equivalent 2yr period and assume a zero beta for the purpose of de-levering and re-levering. We apply a zero per cent gearing constraint, such that negative gearing is not included in those calculations.

From our sample of 21 comparators, there is a wide variation of asset betas. Use of the 65th percentile for estimating a beta estimate which gives a figure of 0.54.

Market evidence

We use a figure of **0.55** for the asset beta. This is consistent with the empirical assessment of market evidence and the mid-point of Generators in the CMA's 2016 Energy Market Investigation (EMI).

Figure 6.1 below illustrates the long-term industry asset beta ranges that we conclude from our analysis, alongside the corresponding ranges determined by the CMA in the EMI. As another point of comparison for judging relative risk, Figure 6.2 shows recent regulatory decisions on asset betas in the UK and Ireland. In general, the asset beta ranges from our analysis are consistent with (although slightly wider than) those of the CMA. The precedent includes the previous Poyry (2018) study for the Best New Entrant Generator.

Figure 6.1: Estimated long term asset beta ranges for energy industry comparator groups as estimated by the CMA (in red – top of chart) and CEPA (in teal – bottom of chart)

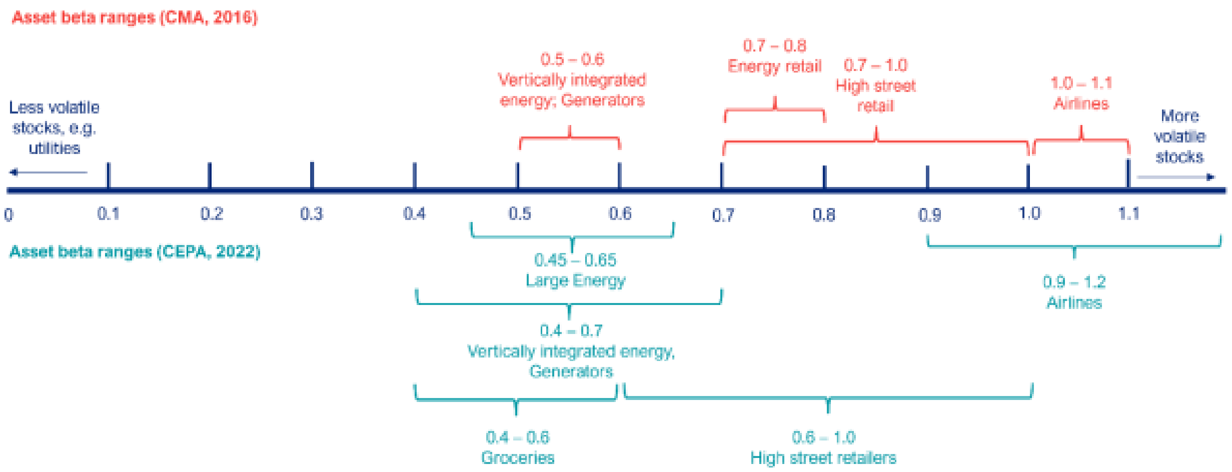
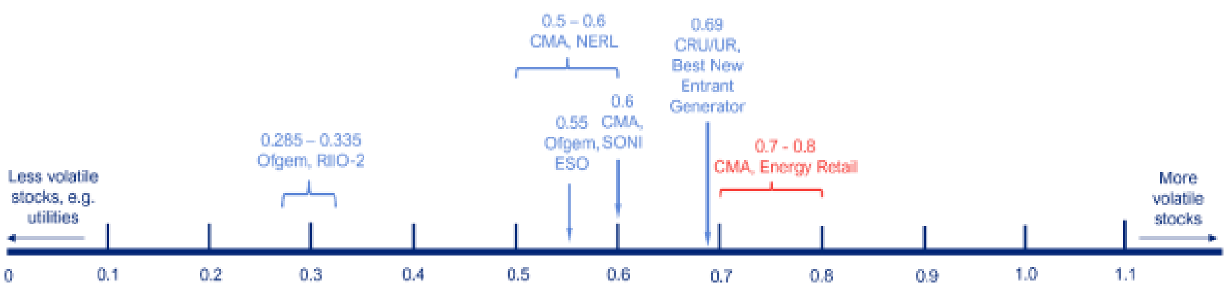


Figure 6.2: UK / Irish precedent on asset beta



Source: CEPA, CMA, Bloomberg

Estimate – NI & IE

The estimate from the stated methodology gives an asset beta that is consistent with regulatory precedent. The asset beta for this study is therefore **0.55**. This is notably below the Poyry (2018) Best New Entrant study of 0.69.

6.2.4. Gearing

Methodology

Notional gearing sets out the mix of debt and equity in funding the business. Our approach utilises market evidence on gearing levels of both publicly listed and privately owned comparators.

We draw upon relevant market evidence in making our assessment. The impact of gearing on the overall cost of capital should be more limited, as the Modigliani-Miller (1958) theory indicates that capital structure does not change a company's value.

Gearing levels will also be a function of the approach adopted by the relevant comparator; a firm using corporate financing will typically have lower levels of gearing relative to a project financed firm/ vehicle, and will also refinance more frequently. The construction phase of projects will also typically have a lower proportion of debt in its financing structure, relative to an operational project.

We utilise the same comparator set as for our beta analysis. We assess the average 2yr gearing over a five-year period to end-July 2022. We use a median estimate to establish our gearing approach.

Market evidence

The approach above gives a gearing estimate of 37%. This is typically lower than the notional gearing assumed for regulated networks (typically in the 50-65% range), however the estimate more closely reflects the risk profile and likely investment. Poyry (2018) used a 40% gearing assumption.

Estimate – NI & IE

We use a consistent gearing assumption of **40%** for gearing in both jurisdictions, as per the Poyry (2018) BNE study.

6.2.5. Cost of debt

Methodology

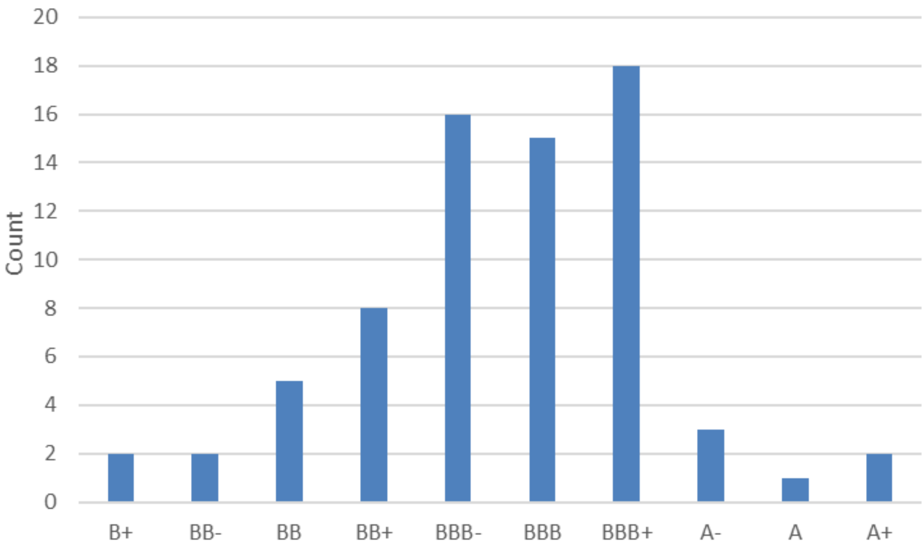
Our approach to estimating the cost of debt involves the use of relevant benchmark indices. We rely on estimates from Bloomberg indices to achieve these.

We first consider the appropriate credit rating that should apply here, based on a review of credit ratings from relevant comparators.

Credit rating

We present the credit ratings, based on a Bloomberg composite rating (of Fitch, Moody's and S&P), of a sample of relevant energy firms. The sample is based on corporates issuing active bonds; the corporates must be domiciled in Europe, issued active Euro-denominated debt and fall into the following BICS classifications; Power Generation, Utilities and Renewable Energy. There are 73 corporates with a credit rating, as shown below.

Figure 6.3: Credit ratings for cost of debt



Source: Bloomberg. Note: there is one company with a rating below B+ not shown (with a CCC rating).

The sample is very varied, but has a large number of investment grade corporates (i.e. BBB- or above).

Empirical estimation

We utilise Markit iBoxx indices for estimating the cost of debt. We rely upon broad BBB rated non-financial corporate indices with tenor of at least ten years (10yr+ index). This is reflective of the expected life of debt.

We use the EUR denominated index for Eurozone and the GBP denominated index for the UK.

We use a 1-month average, as per our approach on averaging for the risk-free rate.

Market evidence

The results from the stated approach are captured below.

Table 6.7: Yields on iBoxx BBB non-financial corporate 10yr+ indices – cost of debt

	Eurozone	UK
Nominal yields, 1m average	3.47%	4.61%

Source: Markit iBoxx

Estimate – NI

We use an estimate of **4.61%** for the NI cost of debt.

Estimate - IE

We use an estimate of **3.47%** for the IE cost of debt.

6.2.6. Tax

We use a corporation tax rate of **25%** for NI and **12.5%** for IE[32].

[32] The corporation tax assumption for NI is based on the stated increase from April 2023, though it is currently 19%.

6.3. Overall WACC

The WACC is shown in Table 6.8 for both jurisdictions.

Table 6.8: Estimates of nominal pre-tax WACC for NI and IE

Parameter	IE	NI
Gearing	40%	40%
Risk-free	1.14%	2.06%
ERP	7.55%	7.37%
Asset Beta	0.55	0.55
Equity Beta	0.92	0.92
Post-tax CoE	8.06%	8.82%
Tax rate	12.5%	25.0%
Pre-tax CoE	9.21%	11.75%
Cost of Debt	3.47%	4.61%
Vanilla WACC	*6.22%*	*7.13%*
Pre-tax WACC	**6.92%**	**8.90%**

Source: CEPA/ Ramboll

We note that the estimate is difficult to compare to other precedent. The most relevant precedent is the previous decision, where Poyry (2018) used a 8.31% nominal pre-tax WACC for IE and 8.32% nominal WACC for NI.

Challenges in comparing this decision to others include that:

- We are setting a 'current' estimate for new investment.
- Network price controls tend to use a real cost of capital, whereas here we calculate a nominal return.
- Risk profiles differ relative to regulated networks, such as Gas Networks Ireland.

Market movements in yields and the broader evidence base can vary the number materially. Indeed, since the data cut-off, we have seen very significant movements in yields. The NI tax rate has also changed, relative to our cutoff date. We propose to update this ahead of a Final Decision.

7. ENERGY MARKET AND SYSTEM SERVICES REVENUES

To determine Net CoNE, we must estimate the revenues which BNE technologies may be able to receive from sources other than the CRM. The main sources of market revenues outside of the CRM are:

- Infra-marginal rents, reflecting revenues which the unit can earn in the electricity market during periods in which the unit is dispatched but is not the marginal unit (i.e., not the most expensive unit required to operate that sets the market price).
- System services revenues, available for the provision of ancillary services to maintain the frequency and voltage of the power system within technical limits.

Our estimates for each of these revenue streams are set out in the following sections.

7.1. INFRA-MARGINAL RENT

Under the concept of marginal pricing, the wholesale price wholesale electricity in the SEM reflects the price of the marginal unit which needs to be dispatched to balance supply and demand. Units that have their bids accepted generally receive this uniform price even if their own bid was below this level. This provides an incentive for generators and demand side units to offer capacity at their short-run marginal cost.[33] If they were to bid higher than short-run marginal cost, they would risk not being dispatched when they would have been able to make a profit, whereas bidding below short-run marginal cost creates the risk of being dispatched at a financial loss.

Over time, positive differences between a short-run marginal cost and uniform wholesale energy price, i.e., infra-marginal rents, provide for the recovery of capital and fixed costs. In this way, infra-marginal rents complement the revenues which the BNE can receive through CRM revenues (i.e., Reliability Option fees) and it is appropriate to subtract these revenues in the calculation of Net CoNE.

Methodology

Infra-marginal rents will naturally vary from one hour to the next and depend on the future technology mix. The technology mix will determine:

- The operational regime of the BNE, including its operating hours and position in the merit order of dispatch.
- The range of prices within a day (or across several days), which will determine the arbitrage opportunities available to an energy storage unit through charging in low price intervals and discharging when the wholesale price is high.

To capture these operational and pricing dynamics, the most robust approach involves wholesale market modelling of the future power system. Ideally, infra-marginal rents would be estimated using the same model used by the RAs for determining CRM parameters.

While it has not been possible to commission specific model runs for this project, we have obtained the results of runs undertaken for the 2025/26 capacity year[34]. As this is the year immediately prior to 2026/27, we consider that these results can provide a reasonable indication of the infra-marginal rents which the BNE may be able to achieve.

For the thermal BNE units, our infra-marginal rent estimates are based on the units modelled for the 2025/26 capacity year. The specific units representing the BNE for the purposes of infra-marginal rent estimates are

---

[33] Short run marginal cost in the case of energy storage can be thought of as the cost of charging the battery, so will reflect the costs incurred in earlier periods when the battery was charged net of round-trip efficiency losses.

[34] The primary purpose of these runs was to assess applications for Unit Specific Price Caps.

relatively modern units which is reflected in their operating hours and merit order position, which are key factors in determining infra-marginal rents. The infra-marginal rent estimates were provided to us by the UR.

For BESS, UR's existing modelling results for infra-marginal rent are less suitable because most of the batteries currently modelled are primarily targeting system services revenues. So, instead of using a 2025/26 modelled result for energy storage, we have estimated potential revenues through the analysis of the hourly prices from the same PLEXOS model runs. We have assumed that:

- A battery with 2 hours of storage completes one full cycle every day.
- The operator has perfect foresight, allowing the battery to charge in the cheapest two hours and discharge in the two most expensive ones.
- The battery has a round trip efficiency of 85%, determined on an AC basis.
- The battery experiences a capacity degradation of 20% over a period of 10 years.
- The battery is constrained to operating between 5% and 95% state of charge.

When these assumptions are applied, the implied infra-marginal rent for a BESS is €25.98 per kW of installed capacity.

As this is a static analysis, it does not account for the impact the energy storage would have on prices. In practice, the presence of energy storage with the ability to time-shift energy would be expected to dampen extreme prices, leading to lower peaks and higher troughs.

Estimate

Table 7.1 sets out the infra-marginal rent values provided to us for the proxy CCGT, OCGT and reciprocating engines, and the results of our analysis of theoretical BESS infra-marginal rents based on historical prices. For these estimates we do not differentiate between IE and NI on the basis that under uniform pricing a similar infra-marginal rent opportunity would exist in either jurisdiction.

Table 7.1: Estimates of infra-marginal rent (€/kW/year – installed)

Parameter	CCGT	OCGT	Engines	BESS
Infra-marginal rent (€/kW/year)	€87.85	€0.57	€0.57	€25.98

At this time, we assume for the purpose of providing estimate of Net CoNE that these revenues are maintained across the 2026/27 to 2035/36 period. We acknowledge that for the gas units this may be an overly optimistic assumption in the context of increasing levels of variable RES generation in the SEM which may reduce the annual run hours of thermal units. This would lead to lower revenues for CCGT units if lower run hours are not offset by higher rents. Hence, it may be appropriate to apply some form of reduction to the CCGT infra-marginal rent figures to reflect lower rents in the later years.

Such a reduction could be based on a 'rule of thumb' or specific market modelling. We leave this question open as a topic which stakeholders can comment on through the consultation. For now, we provide an indicative example of the impact of lower revenues over time.

If we assume that infra-marginal rents were to decline from €87.85/kW/year to zero after 10 years, the discounted future cashflows[35] would provide Net Present Value (NPV) of €400.40/kW. Divided by the assumed 20-year asset life of the CCGT, this total provides average annual revenues of €20.02/kW/year across the life of the asset. Applying this assumption in place of the €87.85 figure would lead to inframarginal rent of €24.27/kW/year when

[35] We have applied a discount rate of 6.92% to match the pre-tax WACC for Ireland identified in section 6.3. We assume that all cash flows are received as a lump sum on 1 April of each year.

expressed on a derated capacity basis in €2026/27. In Section 8, the equivalent figure from CCGT inframarginal rent is €106.48/kW/year.

7.2. System services revenues

In the SEM, system services are procured through the DS3 (Delivering a Secure, Sustainable, Electricity System) programme. There are fourteen[36] separate system services, which can be generally split into two broad categories:

- Frequency control services to maintain system frequency at 50 Hz
- Voltage control services to maintain voltage levels on the system.

Currently, the services are procured under regulated arrangements which were established following the SEM Committee's consultation on procurement design (SEM-14-059) and decision (SEM-14-108) in 2014. The current set of contractual arrangements were established in 2017 (SEM-17-094) and are expected to expire on 30th April 2024.

To establish enduring arrangements to apply beyond April 2024, the SEM Committee launched the System Services Future Arrangements (SSFA) project in 2020. The project consists of three phases: Phase I – Scoping (concluded); Phase II – High Level Design (concluded April 2022); and Phase III – Detailed Design (currently underway). As such, the most recent point of reference for our analysis is the High Level Design decision (SEM-22-012) and we have sought to capture these policy decisions in our analysis. However, key details have been allocated to the Detailed Design phase which is still ongoing. Therefore, we necessarily had to make various simplifying assumptions in estimating revenues.

We have focused our analysis on frequency control services because under normal (i.e., unconstrained) operating conditions these services can be provided from any location in the power system. In contrast, voltage control services are generally more locationally specific, and it is less clear that the BNE would be able to access these revenues. Our analysis is therefore flexible to the location of the BNE. We consider the following services:

- **Reserve services:** FFR, POR, SOR, TOR1, TOR2
- **Ramping services:** RRS, RRD, RM1, RM3, RM8.

We omit consideration of FPFAPR because it is not currently procured and of SIR because this system requirement it expected to be addressed through the fixed-term procurement of a Low Carbon Inertia Service[37] in defined zones. While it is likely that a gas-fired BNE unit will be able to earn some SIR revenue, the uncertainty around the form of procurement and residual value mean that we exclude it from this analysis.

Methodology

Analytically, we consider the BNE's potential system service revenues to be a function of run hours, technology capability, prices, and scalars or other incentives which may apply under the future arrangements. We set out our assumptions for each of these in this order.

Our run hour assumptions are derived from the modelling results which we used for the infra-marginal rent values. Consistent with the modelling, we assume that the CCGT would be online 65.6% of hours in a year, but that the OCGT and reciprocating engines would only operate for 40 hours annually (c. 0.4%).

[36] Currently 2 of the 14 System Services are not procured, namely Fast Post Fault Active Power Recovery (FPFAPR) and Dynamic Reactive Response (DRR). It is expected that these system services will need to be procured in the future.

[37] EirGrid/SONI, 2022, *Consultation on Low Carbon Inertia Service (LCIS) Competitive Procurement*.

The starting point for the capability of the BNE candidates to offer system services are the capability factors developed by EirGrid and SONI for their analysis of 2030 Volumes.[38] These factors are an estimate of the system services capability of each technology as a percentage of the installed capacity. We understand that these factors are calculated at the fleet level and for "established" technologies are based on historical data of contracted capabilities. We use the capability factors for "Gas Turbine – Flexible" (for OCGT, CCGT and reciprocating engines) and "ESPS – Energy & Reserve" (for BESS). These are provided in Table 7.2.

Table 7.2: Capability factor assumptions for BNE technologies (unadjusted)

Technology	FFR	POR	SOR	TOR1	TOR2	RRS	RRD	RM1	RM3	RM8
CCGT	0%	17%	19%	27%	55%	71%	95%	100%	100%	100%
OCGT	0%	17%	19%	27%	55%	71%	95%	100%	100%	100%
Engines	0%	17%	19%	27%	55%	71%	95%	100%	100%	100%
BESS	100%	100%	100%	100%	100%	0%	100%	100%	0%	0%

From this starting point we make a series of adjustments to produce modified capability factors which we consider more suitable for estimating revenues for discrete units (as opposed to the fleet as a whole). The adjustments are:

- The capability of reciprocating engines is assumed to be 25% *higher* than "Gas Turbine – Flexible" (i.e., OCGT) to reflect the operational advantages of the latter, such as shorter start times, higher part-load efficiency, lower sensitivity to ambient conditions, and ability to operate at lower gas pressures than gas turbines.
- Conversely, the capacity of CCGT is assumed to be 25% *lower* than the OCGT assumptions to reflect the complexity, and generally lower efficacy, of providing frequency responses from a steam turbine.
- The capability factors for BESS are capped at 80% to account for imperfect foresight, energy constraints, and competing revenue streams or contractual commitments which could preclude the provision of systems services on some days.

We combine adjusted capability factors with the run hour assumption to provide availability factors in in Table 7.3.

Table 7.3: Availability factors for BNE technologies

Technology	FFR	POR	SOR	TOR1	TOR2	RRS	RRD	RM1	RM3	RM8
CCGT	0%	8.4%	9.3%	13.3%	27.1%	34.9%	95%	100%	100%	100%
OCGT	0%	0.1%	0.1%	0.1%	0.2%	0.3%	95%	100%	100%	100%
Engines	0%	0.1%	0.1%	0.1%	0.3%	0.4%	95%	100%	100%	100%
BESS	80%	80%	80%	80%	80%	0%	80%	80%	0%	0%

We reduce capability to account for forced and planned outages for the BESS units only. This is because the run hour assumptions from the market modelling already reflect forced and planning outages.

Table 7.4: Forced and planned outage rates

Parameter	BESS
FOR	1%
POR	4%

Due to the uncertainty around the future arrangements, we based our price assumption on the existing tariffs. We take the 2021/22 Tariffs which apply under the regulated arrangements and apply a discount in anticipation of lower

[38] EirGrid/SONI, 2021, *System Services – 2030 Volumes: Indicative Portfolio Capability Analysis*.

prices once the services are subject to competitive provision through daily auctions. There is limited evidence for the size of this discount, but one source is the DS3 Volume Capped procurement where the value of the contracts was approximately 18% *of* the value (i.e., a c. 83% discount) had the services been procured through the Volume Uncapped process. We consider that such a discount would be too high in the case of the BNE, as there are a range of factors which could push prices in either direction, including:

- The effect of competition for products to be procured through daily auctions which would exert generally downward pressure on prices.
- New entry by and greater competition between providers of reserve services (i.e., energy storage, and DSU) at the same time of a generally steady requirement for these services.[39]
- Greater demand for ramping services, and, potentially, a new ramping service, as SNSP levels increase towards the 2030 target which would put upward pressure on prices.
- The revenue certainty under daily auctions relative to the Volume Capped procurement – the latter involved providing relatively predictable revenue streams across the six-year terms of the contracts, whereas the value from daily auctions could fluctuate over time.

On balance, we consider that a uniform discount of 20% off the 2021/22 Tariffs is appropriate to capture these countervailing factors in the context of general uncertainty around the market settings and price formation under the future arrangements. This is an uncertain assumption which stakeholders may be able to firm up through the consultation.

The final component of our DS3 revenue calculation is the application of scalars. Scalars are an established feature of the existing regulated arrangements to provide upwards and downwards adjustments to unit compensation to reflect performance, scarcity and specific locational requirements. While some are expected to be adjusted or removed under the future arrangements, we retain some scalars in our analysis to capture the policy intent of the High Level Design. Specifically, we apply:

- Performance scalar of 1 to reflect good performance allowing the BNE to avoid penalty under envisaged Commitment Obligations.
- Product scalar of 1.5 for FFR in the case of BESS; 1 for other technologies. We retain this scalar for continuous provision, currently offered to providers of FFR that also provide all of POR, SOR and TOR1, on assumption that continuous provision will continue to be valued, potentially implicitly through market-based prices, under the future arrangements.
- Location scalar of 1.94 for BESS located in Ireland, on assumption that the enduring regime will contain locational incentives, that the Dublin region will continue to be constrained, and, for this reason, a BESS BNE unit would choose to locate there. It is less certain that BNE thermal plant would be able to locate in the Dublin region, so these units are provided with a locational scalar of 1.

We assume that these revenues are maintained across the 2026/27 to 2035/36 period.

Estimate

The results of this analysis are provided in Table 7.5.

[39] EirGrid/SONI, 2021, op. cit. "reserve requirements in real time operation will continue to be a function of the Largest Single Infeed (LSI) and will not change significantly by 2030".

Table 7.5: Estimates of system services revenues (€/kW/year – installed)

Parameter	CCGT		OCGT		Engines		BESS	
	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland
DS3 revenue (€/kW/year – installed)	€13.85	€13.85	€7.01	€7.01	€7.03	€7.03	€66.48	€57.47

Like the infra-marginal rent analysis, since these values involve an annual run hour assumption, there is scope for these revenues to reduce over time if thermal units are required to run less often. However, this effect is at least partially offset by the potential for system services to be more valuable in the future. Also, some services can be provided without the unit already being synchronised with the grid.

8. ESTIMATING NET CONE

In this section, we present our overall estimates of net CoNE for the T-4 auction taking place in 2026/27.

8.1. Gross CoNE estimates

We present our Gross CoNE estimates using two different forms. Our Gross CoNE has been estimated based on current cost estimates, i.e., values. Given that we are estimating values for a T-4 auction, we roll forward these values to capture expected values in 26/27. We use estimated inflation to do this.

8.1.1. Estimates for 2022/23 values

In the table below, we present Gross CoNE, firstly on a total cost basis (Table 8.1), and then on an annualised per kW of derated capacity basis (Table 8.2). Annualised is based on the assumed economic life of the assets; this is assumed to be 20 years for CCGT, OCGT and reciprocating engines. It is assumed to be 10 years for BESS.

Table 8.1: Gross CoNE inputs

Parameter	CCGT		OCGT		Engines		BESS	
	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland
Total capital fixed costs, €m	395.31	392.02	108.10	106.14	218.78	210.85	81.03	79.58
Annualised fixed costs, €m / yr	37.08	42.64	10.14	11.54	20.52	22.93	11.49	12.34
Recurring costs, €m / yr	28.06	23.97	5.48	4.93	8.76	7.99	3.48	2.79
Total annual costs, €m per year	**65.14**	**66.61**	**15.62**	**16.47**	**29.28**	**30.92**	**14.97**	**15.14**

Source: CEPA/ Ramboll estimates

Table 8.2: Gross CoNE estimate

Parameter	CCGT		OCGT		Engines		BESS	
	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland
Capacity, MW	470.0	470.0	198.6	198.6	200.3	200.3	100.0	100.0
De-rating scalar	0.83	0.83	0.88	0.88	0.88	0.88	0.36	0.36
ARHL scalar	1.00	1.00	1.00	0.43	1.00	0.43	1.00	1.00
Capacity, derated MW	387.75	387.75	175.36	75.41	176.66	75.97	36.20	36.20
Annualised fixed costs, € / derated kW	95.64	109.97	57.82	153.10	116.17	301.90	317.54	341.02
Recurring costs, € / derated kW	72.37	61.81	31.25	65.36	49.59	105.17	96.12	77.10
Gross CoNE, € / derated kW	**168.00**	**171.78**	**89.07**	**218.46**	**165.76**	**407.06**	**413.66**	**418.12**

Source: CEPA/ Ramboll estimates

The option of an OCGT locating in Ireland provides the lowest gross CoNE on a derated basis. This result is largely a function of the lower investment costs of this technology coupled with reoccurring fixed costs which are similar across the gas-fired technologies. The application of the ARHL derating factor to the OCGT and reciprocating engine units locating in Northern Ireland elevates those Gross CoNE estimates above the other thermal technologies.

8.1.2. Estimates for 2026/27

To convert price into 2026/27 expected values, we require a four-year view of inflation. For the purpose of this study, we have used an approach consistent with the previous Poyry study of applying a 2.0% long-term inflation estimate for both jurisdictions. We apply this uplift to all costs estimated in 2022/23 values.

We note that inflation expectations are currently materially elevated relative to this long-term trend. This will be reflected to some extent in our nominal cost of capital parameters. Values in parentheses reflect the year for which values have been estimated, i.e., 22/23 reflects values expected for 2022/23.

Table 8.3: Gross CoNE – expected 26/27 values

Parameter	CCGT		OCGT		Engines		BESS	
	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland
Gross CoNE, € / derated kW (22/23)	168.00	171.78	89.07	218.46	165.76	407.06	413.66	418.12
Inflation adjustment	1.08	1.08	1.08	1.08	1.08	1.08	1.08	1.08
Gross CoNE, € / derated kW (26/27)	**181.85**	**185.94**	**96.42**	**236.47**	**179.43**	**440.62**	**447.76**	**452.59**

Source: CEPA / Ramboll estimates

We note that the OCGT locating in Ireland reflects the lowest Gross CoNE estimation, across our considered technologies.

8.2. Revenues

We similarly need to uplift our DS3 revenues, estimated using current 2022/23 values, to reflect estimated revenues in 2026/27; this requires a four-year adjustment. We use the same inflation adjustment as with gross CoNE for this purpose.

For IMR revenues, the input data reflects model outputs for 2025/26. As such, we apply a one-year inflationary adjustment, also using a 2% long-term inflation assumption for both jurisdictions to convert into expected 2026/27 revenues.

Our revenues reflect euros per derated kW, consistent with the approach on our gross CoNE estimates.

Table 8.4: Revenues, adjusted for inflation

Parameter	CCGT		OCGT		Engines		BESS	
	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland
Infra-marginal rent (€/ derated kW), 25/26	104.40	104.40	0.63	1.47	0.63	1.47	70.36	70.36
Infra-marginal rent (€/ derated kW), 26/27	106.48	106.48	0.65	1.50	0.65	1.50	71.77	71.77
DS3 revenue (€/ derated kW), 22/23	15.76	16.79	7.94	18.46	7.97	18.54	183.65	158.76
DS3 revenue (€/ derated kW), 26/27	17.06	18.17	8.59	19.98	8.63	20.06	198.78	171.84
Total revenues, (€ / derated kW), 26/27	**123.54**	**124.66**	**9.24**	**21.49**	**9.27**	**21.57**	**270.55**	**243.61**

Source: CEPA / Ramboll estimates

8.3. Net CoNE, 'level-nominal'

Table 8.5 presents the Gross CoNE and Net CoNE alongside the revenue streams which constitute the difference between these two metrics. All parameters are initially reported in terms of derated capacity using expected 2026/27 values and constitute the main results of this report. This approach assumes that revenues and costs remain constant in nominal terms over the life of the generation technologies.

Table 8.5: Net CoNE, per kW de-rated – level-nominal

Parameter	CCGT		OCGT		Engines		BESS	
	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland
Gross CoNE (€ / derated kW), 26/27	181.85	185.94	96.42	236.47	179.43	440.62	447.76	452.59
Revenues (€ / derated kW), 26/27	123.54	124.66	9.24	21.49	9.27	21.57	270.55	243.61
Net CoNE (€ / derated kW), 26/27	**58.31**	**61.28**	**87.18**	**214.99**	**170.15**	**419.05**	**177.20**	**208.98**

Source: CEPA / Ramboll estimates

We note that the Irish CCGT reflects the lowest Net CoNE option, with only a small difference between the two jurisdictions considered. However, as discussed in Section 7.1, we acknowledge that the infra-marginal rent assumption may be overly optimistic for CCGT, leading to a Net CoNE which is too low. It may be appropriate to apply some form of reduction to the CCGT infra-marginal rent figures to reflect lower rents in the later years. One way to do this would be to conduct market modelling to estimate infra-marginal rents for later years; however, such estimates are not available at this time. Stakeholders may wish to comment on the most appropriate approach for arriving at this reduction through the consultation.

In contrast, the Net CoNE estimates for other technologies are less affected by this issue. In the case of the OCGT and reciprocating engine units, this is due to their much lower market revenues owing to their lower annual run hours.

8.4. Net CoNE, 'level-real'

The 'level-nominal' results assume that one-off recurring costs and revenues remain constant in nominal term over the operational life of the asset. One-off costs are incurred up-front and therefore will not change. We utilise Interest During Construction (IDC) to roll-forward the fixed one-off costs, with a nominal cost of capital applied within the annuity calculation.

The results below show how our results differ when we assume that recurring costs and revenues remain constant over the operational life in real terms i.e., increasing by economy-wide inflation each year. All figures shown below represent expected 2026/27 values and relate to de-rated capacity.

Where revenues are higher than recurring costs (e.g., for CCGTs), the use of level-real costs reduce the net CoNE estimate. For CCGTs, we have noted above that the assumption for 26/27 may overestimate the likely IMR over the economic life of the generation plant. A further (upwards) adjustment exacerbates that potential issue. If future market modelling is conducted to estimate revenues for future years, no adjustment will be required to those derived values.

To address the issue around using higher IMR estimates through this adjustment, we have included an additional line at the bottom of Table 8.6 that excludes any adjustment to revenues i.e., we assume level-nominal revenue and level-real recurring cost.

We use an NPV-equivalence principle to convert values. We use the relevant nominal WACCs derived for different technologies, over the relevant asset lives.

Table 8.6: Net CoNE, per kW de-rated – level-real

Parameter	CCGT		OCGT		Engines		BESS	
€/ de-rated kW, 26/27	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland	Ireland	Northern Ireland
Annualised investment	103.52	119.03	62.59	165.72	125.74	326.78	343.71	369.13
Recurring costs – level-nominal	78.34	66.91	33.83	70.75	53.68	113.83	104.05	83.46
Revenues – level-nominal	123.54	124.66	9.24	21.49	9.27	21.57	270.55	243.61
Net CoNE, level-nominal	**58.31**	**61.28**	**87.18**	**214.99**	**170.15**	**419.05**	**177.20**	**208.98**
Recurring costs – level-real	91.14	76.99	39.36	81.41	62.46	130.98	112.69	90.13
Recurring costs - adjustment	*12.80*	*10.08*	*5.53*	*10.66*	*8.77*	*17.15*	*8.65*	*6.67*
Revenues – level-real	143.74	143.44	10.75	24.72	10.79	24.82	293.04	263.09
Revenues - adjustment	*20.19*	*18.78*	*1.51*	*3.24*	*1.52*	*3.25*	*22.49*	*19.48*
Net CoNE, level-real	**50.92**	**52.58**	**91.20**	**222.41**	**177.41**	**432.95**	**163.36**	**196.17**
Net CoNE, level-real, recurring adjustment only	71.12	71.36	92.71	225.64	178.93	436.20	185.85	215.65

UK

Queens House

55-56 Lincoln's Inn Fields

London WC2A 3LJ

T. **+44 (0)20 7269 0210**

E. **info@cepa.co.uk**

www.cepa.co.uk

Australia

Level 20, Tower 2 Darling Park

201 Sussex Street

Sydney NSW 2000

T. **+61 2 9006 1308**

E. **info@cepa.net.au**

www.cepa.net.au

cepa-ltd @cepaltd