COST OF NEW ENTRANT PEAKING PLANT AND COMBINED CYCLE PLANT IN I-SEM

A report to the Utility Regulator and the Commission for Regulation of Utilities

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1. INTRODUCTION

1.1 Introduction

Pöyry Management Consulting was commissioned by the Utility Regulator ('UR') and the Commission for Regulation of Utilities ('CRU') (collectively referred to as the Regulatory Authorities ('RAs')) to produce a report to inform the determination of the gross and net Cost of New Entry ('net CONE'). The gross and net CONE are used to determine some key parameters for the T-4 Capacity Market auction for Capacity Year 2022/23.

Unlike previous BNE determinations, which were solely focused on peaking plants, this independent report provides for an estimate of the net CONE for two reference technologies:

- a 'peaking plant' that meets a set of criteria similar to those previously used to determine the Best New Entrant ('BNE') peaking plant under the SEM CPM; and
- a Combined Cycle Gas Turbine ('CCGT') of a size that would not exceed that of the current largest infeed in the All-Island system.

This report is not aimed at providing for a detailed description of the mechanics of the I-SEM Capacity Remuneration Mechanism ('CRM') and we expect that the reader has a reasonable understanding of the detailed design of the I-SEM CRM.

1.2 Structure of this report

The report is structured as follows:

- Section 2 provides for an overview of the new Capacity Market and explains how the BNE price (i.e. net CONE) is expected to be used.
- Section 3 outlines the selected options for the different reference technologies.
- Section 4 details the estimation of the capital and annual fixed costs for the reference technologies.
- Section 5 provides the expected System Services and net energy market revenues for the reference technologies.
- Section 6 details our analysis for the cost of capital.
- Section7 summarises the gross and net Cost of New Entry for the reference technologies.

1.3 Conventions

The following conventions have been used in this report:

- All monetary values quoted in this report are in real 2017 Euros, unless otherwise stated.
- Annual data relates to calendar years running from 1 January to 31 December, unless otherwise identified.

1.3.1 Sources

Unless otherwise attributed the source for all tables, figures and charts is Pöyry Management Consulting.

2. BACKGROUND

2.1 I-SEM Capacity Market

I-SEM will have an explicit Capacity Remuneration Mechanism ('CRM'), based on competitive procurement. Unlike the previous Capacity Payment Mechanism ('CPM'), where relevant payments can be captured by all capacity, under the I-SEM CRM, only providers that are successful in a Capacity Auction will receive a capacity payment. Each Capacity Auction yields a single, uniform price, which is paid to all successful capacity providers.

In exchange, capacity providers are required to enter a one-way contract for differences, a Reliability Option ('RO'). Capacity covered by such a contract is then liable for a difference payment equal to the difference between the market price and the RO Strike Price, when such difference is positive. The difference payments are calculated against the relevant reference market, which can include the Day Ahead market, the intraday market and the Balancing Market.

Auctions for each Capacity Year (running from 1 October to 30 September of the following year) will be held (around) four years ahead of such Capacity Year (T-4 auctions). Supplemental auctions will take place approximately one year ahead (T-1) if necessary. The first T-1 auction for Capacity Year 2018/19 took place in December 2017. The first T-4 auction for Capacity Year 2022/23 will be held in March 2019.

The Capacity Market is governed by the Capacity Market Code ('CMC'), and the CMC can be referred to for further details of the Capacity Remuneration Mechanism.

The Regulatory Authorities ('RAs') are required under the CMC to define the:

- New Capacity Investment Rate Threshold ('NCIRT');
- Auction Price Cap ('APC'); and
- Existing Capacity Price Cap ('ECPC').

The above parameters are derived from the net Cost of New Entry ('net CONE') or the gross BNE capital investment cost in the case of the NCIRT.

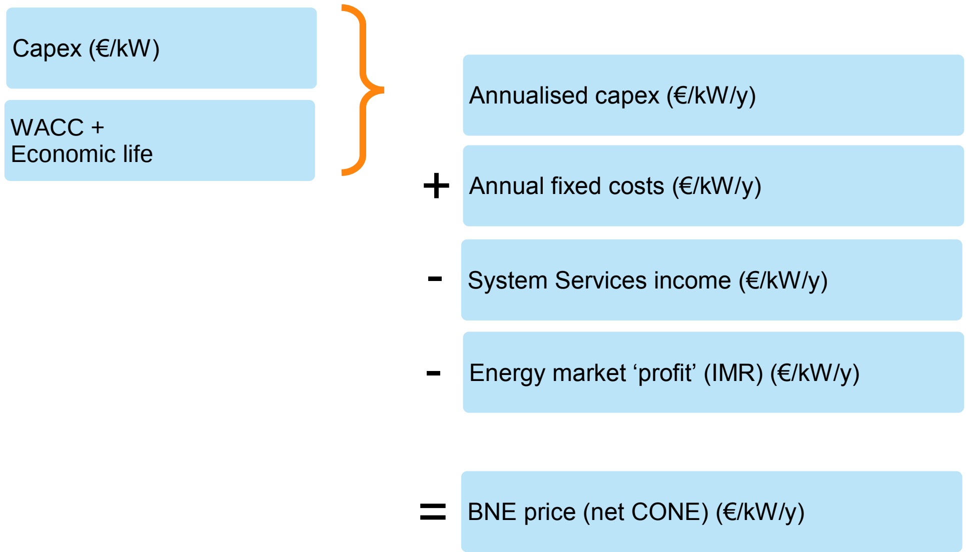
2.2 What is the net CONE?

The net CONE is a measure of the annual revenue (€/kW/y in real terms) required by a capacity provider to cover its fixed costs of operation net of expected inframarginal rent (captured through the energy market) and System Services income. **Error! Reference source not found.** presents a stylised calculation of the net CONE, made up from the following elements:

- annualised capex:
  - the capital cost are converted to an annuity based on an assumed economic lifetime and a Weighted Average Cost of Capital ('WACC').
- annual fixed costs;
- net energy and ancillary services income:
  - DS3 System Services income; and

– inframarginal rent.

Figure 1 – Calculation of the net CONE



Since the net CONE may differ across capacity providers, in the context of the CRM, the net CONE of the Best New Entrant ('BNE') technology – the BNE net CONE or BNE Price – is applied.

2.3 Which reference technologies should be considered?

Under the SEM CPM, BNE assessments focussed on peaking plant with very low running hours as the intention was for capacity payments to reflect the cost of efficiently meeting the marginal MW of demand. Decisions on the BNE price were made annually, based on periodical review of the BNE choice and associated cost expectations.

However, with the I-SEM CRM introducing an auction process for capacity and offering longer-term capacity contracts, the BNE technology will be revealed through competition, reflecting the decisions of investors in the market. Under these circumstances, restricting the choice of the BNE technology to a peaking plant may be inefficient.

Combined Cycle Gas Turbines ('CCGTs') have been the preferred technology choice over the recent past in the All-Island system with very few Open Cycle Gas Turbines ('OCGTs') or other peaking plants having been recently commissioned. This comes despite the persistent choice of an OCGT as the BNE in all previous determinations. We believe that actual market outcomes should not be ignored, and see this as an indication that OCGTs (or other peaking plants) may be less economic when compared to CCGTs.

We therefore propose to explore the net CONE of a CCGT (of a size that would not exceed the size of the current largest infeed in the All-Island system), in addition to the net CONE of a peaking plant that meets the set of criteria previously used to determine the Best New Entrant ('BNE') peaking plant under the SEM CPM.

This choice is not unconventional. The net CONE of CCGTs has been considered in other capacity markets, including GB and PJM.

The choice of the reference peaking plant is something we look at in more detail, and our analysis is presented in Section 3.1 When compared to previous BNE determinations, we have now considered additional technologies that could be thought of as 'peaking' or marginal MW providers, including solutions that have recently become more popular – battery storage and reciprocating engines.

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3. SELECTION OF REFERENCE TECHNOLOGIES

This section outlines our evaluation process to identify the reference technology choices that are most likely to be made by a rational investor in a peaking plant and a CCGT plant.

When it comes to the selection of the best new entrant peaking plant, our approach is similar to that used in previous BNE determinations. We have sought to reflect the feedback from previous BNE calculations and update the analysis in light of recent market developments.

3.1 Technology selection for reference peaking plant

3.1.1 Technology options for reference peaking plant

The starting point for our technology selection process is to develop a list of options capturing all available technologies, which could be considered (or act) as 'peaking plants'. In previous BNE determinations the following have been included:

- Interconnectors;
- Aggregated Generating Units ('AGUs');
- Pumped storage ('PS'); and
- Open cycle gas turbines ('Frame OCGTs').

We have extended the above list and included the following 'peaking plant' technologies:

- Battery storage;
- Compressed air energy storage and flywheels; and
- Utility scale open cycle gas fired reciprocating engines

In the following sub-sections we briefly discuss the technology choices listed above and the rationale behind our choice. It has to be noted that exclusion of any of the above technologies from further consideration as candidates for the reference peaking plant does not mean they are in any way excluded from participating in the Capacity Market and their ability to be awarded a capacity contract. If anything, should their costs be lower than the selected reference peaking plant, then they would be in a favourable position.

3.1.1.1 Interconnectors

Interconnectors are a unique 'technology' type when it comes to their contribution to the security standard – they are not a generating unit in their own right, rather act as a means of transporting energy and capacity from a neighbouring zone. The definition of the capacity credit of an interconnector will depend on the connecting market and assumptions regarding the evolution of the capacity mix both in the All-Island system and the connected market. This introduces a level of uncertainty with regards to the degree that interconnectors can contribute to reliably meet the last MW of demand.

3.1.1.2 Aggregated Generating Units ('AGUs')

The capital costs of Aggregated Generating Units are difficult to define, and we, therefore, believe that this would be a rather unconventional choice.

3.1.1.3 Pumped Storage

To our knowledge, there are limited sites for the development of commercially viable pumped storage projects in Ireland and Northern Ireland. International experience suggests that the cost of pumped storage can vary significantly across different sites.

3.1.1.4 Compressed air energy storage ('CAES')

Compressed air energy storage ('CAES') is an alternative to grid-scale batteries, but can only be developed in specific locations in the proximity of storage caverns. There is no extensive experience with commercial applications of CAES and its cost is relatively uncertain.

3.1.1.5 Flywheels

Unlike CAES, there is significantly more experience with flywheels, but it was only recently that flywheels started being considered for large-scale energy storage applications. They are better suited for providing power for short periods (seconds to minutes). The lack of extensive commercial experience with such technologies and their use (in some cases) for providing more short term response (i.e. frequency response), rather than output over longer periods of time, means that these technologies may not necessarily be prudent choices for the reference peaking plant.

3.1.1.6 Battery storage

On the other hand, batteries are becoming increasingly widespread, and could be considered as a potential choice for the reference peaking plant in the future. Costs have dropped substantially over the last few years and there may be scope for further reductions. In the context of the All-Island system, they are expected to be used primarily for the provision of System Services, and in particular Fast Frequency Response ('FFR'). This means their primary source of revenue in I-SEM may come from the provision of DS3 System Services, and will most likely be determined from the result of the auction for 'high availability' providers. This complicates the determination of expected DS3 income, and, as a result, the net CONE definition for battery storage. Until there is greater certainty about the cost of batteries and their business model under I-SEM, we consider that these should not be used as the reference peaking plant.

3.1.1.1 Open cycle reciprocating engines

Modern reciprocating engines used for power generation are internal combustion ('IC') engines in which an air-fuel mixture is compressed by a piston and ignited within a cylinder. The expanding combustion gases push the piston to the end of the cylinder, converting the linear movement of the piston into the rotating movement of a crankshaft to generate power.

Reciprocating internal combustion ('IC') engines are characterized by the following types:

- spark ignition:
  - The spark ignited engine ('SG type') is based on the Otto cycle, and uses a spark plug to ignite an air-fuel mixture injected at the top of a cylinder.
- compression ignition (also known as diesel engines):
  - In diesel engines, air is compressed until the temperature rises to the auto-ignition temperature of the fuel. As the fuel is injected into the cylinder, it immediately combusts with the hot compressed air.
- Dual-fuel engines ('DF') engines:
  - DF engines are designed with the ability to burn both liquid and gaseous fuels. In DF engines, when operating in gas mode, the compression of the air/gas mixture with the piston does not heat the gas enough to start the combustion process, and therefore some additional energy needs to be added. This is done by injecting a small pilot fuel stream. A liquid fuel such as diesel has a lower self-ignition temperature than natural gas and the heat in the cylinder close to the top position is enough to ignite the liquid fuel, which in turn creates enough heat to cause the air/gas mixture to burn. The amount of pilot fuel ranges from 1% to 2% of the total fuel consumption at full load.

Diesel engines are generally more efficient than SG engines (typically around 44% for a diesel engine and 42% for a SG engine).

Individual engines are available in capacity sizes ranging from a few hundred kilowatts up to around 20 MW. The larger capacity units tend to be medium speed engines (between 300 to 1000 rpm) which are mainly derived from marine and locomotive engines. The smaller capacity units tend to be high speed engines (above 1000 rpm). The high speed engines generally have the lowest specific capital cost, but also tend to have lower efficiencies and higher wear rates. However, these factors are often less important than capital costs for limited duty cycle applications.

Based on the above we consider there are two possible configurations for a new build open cycle reciprocating engine based peaking plant.

At one end of the spectrum would be a plant based on a large number of smaller capacity containerised high speed engines. A 200MW capacity plant would require 137 high speed engines, assuming an engine size of 1.5 MW, occupying a site area of around 7.5 hectares. As dual fuel capability is uncommon at this engine size, the engine choice is between diesel engines or SG type engines. In view of the consultation issued by the Department of Agriculture, Environment and Rural Affairs (DAERA) in June 2017 regarding the tightening of emissions limits for diesel engines[1], we consider it prudent to assume that diesel engine would need to be fitted with secondary abatement equipment to control NOx emissions. This means that diesel engines would be cost effective. Furthermore, the need to comply with the Secondary Fuel Oil Obligation in Ireland and the Fuel Switching Agreement in Northern Ireland, means that a gas fired plant, based on SG engines, is also not considered practicable.

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[1] DAERA, CONSULTATION on Transposition of the Medium Combustion Plant Directive including the regulation of thermal electricity generators, June 2017.

At the other end of the spectrum is a plant based on a smaller number of large capacity medium-speed engines. A 200MW capacity plant would require 20 medium speed engines, assuming an engine size of 10 MW, occupying a site area of around 5.5 hectares. For this type of engine, dual fuel capability is an option and it is expected that emissions limits could be complied with using only primary NOx reduction techniques. The specific capital cost for a plant of this nature is estimated to be within the range 550-650€/kW, which is more expensive than the equivalent open cycle gas turbine plant (estimated at around 500 €/kW as outlined later in this report).

Therefore considering capital cost alone, we conclude that an open cycle reciprocating engine plant is unlikely to be the technology choice for a rational investor in a new peaking plant in Ireland and Northern Ireland, solely on the basis of a 'static' MW remuneration. Some reciprocating engines tend to have enhanced start-up and ramping capabilities. If these characteristics are valuable to the system, and this 'flexibility' can be monetised through participation in the energy markets and from System Services payments, then engines could be a more efficient choice, and the capital cost difference could be offset.

3.1.1.2 Open Cycle Gas Turbine ('OCGT')

A gas turbine consists of three main sections mounted on the same shaft:

- the compressor;
- the combustion chamber; and
- the turbine.

Ambient air is drawn into the compressor where it is compressed to a pressure of up to 30 bar. Fuel and compressed air are burnt in the combustion chamber at temperatures of between 1000 ºC and 1600 ºC. After the combustion process, the hot gas expands through the turbine section. It is in the turbine section where the thermal energy in the hot gas is converted into the mechanical energy which drives both the compressor section and the electrical generator.

Individual gas turbines are available in capacity sizes ranging from a few hundred kilowatts up to around 510 MW. For unit sizes in the range 50MW to 200MW, efficiencies typically vary between 34% and 38% for the heavy duty frame type gas turbines.

The number of gas turbines has grown significantly over the past decades, driven by technical improvements in gas turbine technology and an abundant supply of natural gas at favourable prices. Gas turbines are nowadays commonly used for electricity production in both base load and peaking applications.

We believe that the OCGT should continue to be considered as the most (proven) economical technology choice for the reference peaking plant, given the obvious cost difference with some of the other technologies and the uncertainties attached to a subset of those.

3.1.2 Long list of gas turbines

Stationary gas turbines for power generation are classified into two main groups according to their design characteristics and thermodynamic parameters:

- heavy duty frame type gas turbines; and
- aero-derivative type gas turbines (derived from aircraft engines).

Aero-derivative gas turbines are available in unit sizes up to 100 MWe and offer efficiencies of around 42%. They also offer faster start up times than the heavy duty frame type gas turbines, being capable of reaching full load in 10 minutes from a cold start.

The heavy duty frame type gas turbines are available in unit sizes up to 510 MW. For unit sizes in the range 50MW to 200MW, efficiencies typically vary between 34% and 38%. The heavy duty frame type gas turbines generally offer slower start up times than the aero-derivative type, however the largest units within the considered range are still generally are capable of reaching full load in less than 20 minutes from a cold start.

There are some key differences in the maintenance regimes between aero derivative and large industrial gas turbines. Aero-derivative type gas turbines can be started and stopped regularly without penalty and are usually maintained on an operating hours only basis. In contrast, for heavy duty frame type gas turbines, maintenance penalties are incurred each time the unit is started and in peaking duty, where many starts are involved, maintenance can be on a starts basis rather than hours.

In general, major maintenance on aero derivatives is more expensive than large industrials. Aero derivatives cannot usually be maintained in the field. Normal practice is to change-out the core engine, which due to the modular design can be done within 24 hour shutdown, but this requires the owner to contract for a spare or lease module.

A long-list of gas turbines is presented in Annex A. This is intended to cover all product offerings from the major gas turbine suppliers, including both heavy duty frame type and aero derivative type gas turbine models, in the 30MW to 200MW capacity range.

3.1.3 Initial filtering of gas turbines

The long list of gas turbines was put through an initial filtering process using criteria that a rational investor would consider when deciding which options are best suited for this type of application. The criteria used for initial filtering were as follows:

- Is the gas turbine model commercially proven?
- Can the gas turbine model operate on distillate fuel oil as back up fuel?
- Can the gas turbine model comply with the environmental requirements?
- Can the gas turbine model reach full load from a cold start in less than 20 minutes?

These filtering criteria are discussed in more detail in the following sections. We have assessed this requirement based on our in house knowledge and experience and information available in the public domain. The results of the initial filtering process are presented in Annex A.

3.1.3.1 Commercially proven

We have only considered gas turbines which have a proven track-record. Definitions of what is a commercially proven technology may vary, however the criterion we have adopted is that the model should have over 8,000 hours of commercial operation at three different sites.

3.1.3.2 Capability to operate on back up fuel

We have only considered gas turbine models which are capable of operating on distillate fuel oil as a backup fuel. This is to comply with the requirements of the Secondary Fuel Oil Obligation in Ireland and the Fuel Switching Agreement in Northern Ireland.

3.1.3.3 Capability to meet environmental requirements

We have only considered gas turbines which can comply with statutory environmental emission limits. Those limits, to comply with the Industrial Emissions Directive ('IED'), are taken from the the "best available techniques reference document" for Large Combustion Plants (LCP BREF)[2]. For gas fired operation the NOx BAT-associated emission levels (BAT-AELs), contained in the LCP, are considered achievable by most modern gas turbines using only primary NOx reduction techniques (i.e. the OEM's standard dry low NOx type combustors).

For distillate oil fired operation the indicative values for NOx, SO_2 and dust are considered achievable by most modern gas turbines. It should be possible to meet the NOx and dust indicative values using the OEM's standard combustors. It should be possible to meet the indicative value for SO_2 by procuring commercially available low sulphur distillate fuel oil.

3.1.3.4 Capability to meet minimum start-up time

Peaking plants are used to provide an emergency power reserve to replace sudden generation losses or to respond to unpredictable changes in demand. As such, the full output of the peaking plant is typically required to be available to the system operator within 20 minutes of notification. This is in line with what the TSOs have defined as a necessary operational requirement for any new peaking plant.

Based on the above we have only considered gas turbine models which are capable of reaching full load in less than 20 minutes from a cold start.

3.1.4 Short-list of gas turbines

The remaining gas turbines after the initial filtering process have been compared on an equipment cost / efficiency basis in the figure below.

Thermoflow Inc provide a suite of engineering tools that are well-established and recognised throughout the power generation industry. Performance and cost data in the figure below has been derived using the Thermoflow GTPRO software (version 26.1 library) and associated PEACE module. For gas turbine based power plants GT PRO allows the user to input design criteria and assumptions and the program computes heat and mass balance, system performance, component sizing etc. When run in conjunction

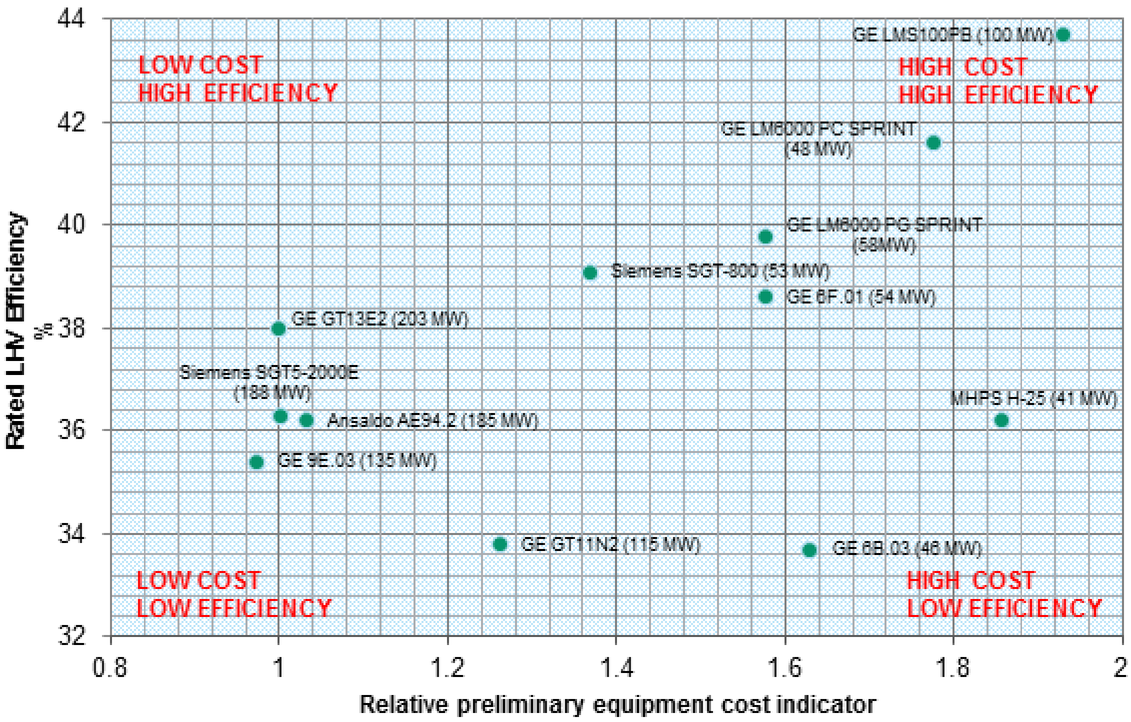
2 http://eippcb.jrc.ec.europa.eu/reference/BREF/LCP_FinalDraft_06_2016.pdf

with the PEACE module, the programs can provide extensive engineering and cost estimation details. PEACE also enables the user to obtain costs for different geographic/market locations.

The values were cross checked against the Gas Turbine World 2016-17 Handbook (volume 32 published in December 2016). This handbook is recognised for use in obtaining basic application type data. Some discrepancies were found between the costs estimated using the PEACE module and the cost data contained in the Gas Turbine World Handbook. In such cases the costs were adjusted to be better aligned with those given in the Gas Turbine World Handbook.

Performance figures are for ISO reference conditions (15°C, 60% RH and sea level altitude) when firing natural gas. Efficiencies are quoted on a lower heating value dry basis (LHV dry basis).

Figure 2 – Relative preliminary equipment cost indicator



In the top right hand corner of the above figure are the “high cost, high efficiency” machines. These are generally the aeroderivative type gas turbine models such as the GE LM6000 and the GE LMS100.

In the bottom left hand corner of the above figure are the “low cost, low efficiency” machines. These are generally the larger heavy duty industrial gas turbines and as expected due to economies of scale, the largest capacity machines yield the lowest specific costs.

When it comes to a peaking plant that is expected to run for less than 500 hours per annum, the specific capital cost is a much more relevant consideration for an investor than the plant efficiency. On this basis, we conclude that the machines with the lowest specific capital cost should be shortlisted for further evaluation. These are:

- General Electric GT13E2;
- Ansaldo Energia AE94.2;
- Siemens SGT5-2000E; and
- General Electric 9E.03.

3.1.5 Final selection of gas turbine

In order to make the final selection, the shortlisted gas turbines were subjected to a more detailed assessment of the plant net electrical output and EPC contract price. To maintain continuity, and provide a good comparison with previous BNE determinations, the approach for the cost estimation has remained generally the same.

3.1.5.1 State of the gas turbine market

According to the Gas Turbine World Handbook 2016-17 on a unit count basis, order for heavy duty frame type gas turbines was expected to be down 19% in 2016 compared to previous year. The Handbook reports however that activity is expected to rebound in 2017 driven by relatively low natural gas prices and coal plant retirements.

Due to the specialised nature of the equipment there are a limited number of equipment suppliers. In recent years, the number of gas turbine manufacturers on the market has continued to shrink, owing to the competitive nature of the business. Recent examples include:

- Mitsubishi Heavy Industries and Hitachi merged their thermal power businesses under the name Mitsubishi Hitachi Power Systems (‘MHPS’) in 2014.
- Siemens acquired Rolls Royce in the same year.
- General Electric acquired the power and grid businesses of Alstom in 2015. As part of this same transaction, Ansaldo acquired all of Alstom’s intellectual property rights for the latest ratings of the GT26 and GT36 gas turbines.

Manufacturers continue to add new models and upgrade older models. As shown in Table 1, the SGT5-2000E gas turbine received a significant upgrade in the last year.

Table 1 – Development in net electrical output for candidate GTs (MW)

GT model	Previous BNE report	This BNE report
GT13E2	203	203
SGT5-2000E	172	188
Ansaldo AE94.2	185	185
9E.03	132	135

3.1.5.2 EPC cost and performance estimation

The four shortlisted gas turbines were evaluated for the following fuel cases:

- distillate fuel oil as the primary fuel (’distillate’ option) ; and
- natural gas as the primary fuel and distillate fuel oil as the secondary fuel (‘dual fuel’ option).

The four gas turbines were modelled using the latest updated version of GT PRO and its associated cost estimating program PEACE. The cost outputs from PEACE were cross checked against the Gas Turbine World 2016-17 Handbook. In cases where a large discrepancy was noted, the outputs were adjusted to be better aligned with the price levels given in the Gas Turbine World Handbook.

Performance figures were based on ambient conditions corresponding to the grid’s winter peak since this is the most likely scenario for the utilization of the peaking plants.

When firing on natural gas, we have assumed the gas turbines will be fitted with the OEM’s standard dry low NOx combustion technology. We have not considered water injection for power augmentation. The benefits of water injection are in any case considered limited as we are considering low ambient temperatures.

When firing on distillate we assume the use of water injection for NOx emission abatement. The water injection flow rate was set equal to whichever is the lower of the fuel mass flow rate or the limit allowed within GT PRO.

The lifetime output degradation of the plants was maintained at 2% for the gas fired cases and 2.5% for the distillate fired ones. The inlet and outlet draught losses were considered to be 6 mbar and 12.5 mbar respectively.

The resultant specific EPC cost and net electrical output estimates are presented in Table 2[3].

[3] We use Republic of Ireland as the basis for assessing EPC costs. The EPC costs for Northern Ireland will be slightly lower due to the lower assumed gird connection voltage level (110kV for Northern Ireland versus 220kV for Republic of Ireland).

Table 2 – Specific EPC cost estimate and power output for shortlisted plants in Republic of Ireland

Plant Type	Fuel Type	Average Lifetime Output (MW)	Specific EPC Cost (€/kW)
GE GT13E2	Distillate	186.0	519.6
	Dual	203.9	482.8
Ansaldo AE94.2	Distillate	187.5	503.6
	Dual	191.1	489.9
Siemens SGT5-2000E	Distillate	190.2	484.6
	Dual	198.6	461.1
GE9E.03	Distillate	138.1	516.6
	Dual	141.3	500.1

Based on the given evaluation criteria, the reference new entrant peaking plant for 2017 is a **Siemens SGT5-2000E** and this is also considered appropriate for use as the BNE peaking plant for CY 2022/23. This is purely for the purposes of selecting a representative model for further consideration and is not intended to reflect a preference for a particular manufacturer. The results of a more detailed acquisition level analysis may favour a different manufacturer.

Both the distillate and the dual fuel options are carried over for further analysis in the following sections for locations for both Northern Ireland and Ireland.

3.1.5.3 Technical assumptions used for selected reference peaking plant

The following has been built in to the performance and cost models for the Siemens SGT5-2000E plant option:

- Ambient conditions at the grid's winter peak.
- Transmission voltage of 110kV for Northern Ireland and 220kV for Republic of Ireland.
- Distillate storage of 3.5 days at maximum plant load for the distillate option.
- Distillate storage of 3.0 days and 5.0 days at maximum plant load for the dual fuel option in Republic of Ireland and Northern Ireland respectively.
- Water injection was only used when distillate firing.
- No fogging or inlet air evaporative cooling employed.
- No Selective Catalytic Reduction for NOx control.

- No black-start capability (it is assumed that had black-start capability been included, the additional costs would have been offset by the subtraction of the associated ancillary service revenue).
- Gas network pressure does not drop below 30 bar. No gas compressors were considered.
- Average lifetime draught losses of 6 and 12.5 mbar for inlet and outlet respectively.
- Average lifetime degradation for power output of 2.5% and 2.0% for distillate and gas fired options respectively.

3.2 Technology selection for reference CCGT plant

3.2.1 Overview of historical investment choices

As discussed in Chapter 2, we are investigating the net CONE of a CCGT alongside the net CONE of a peaking plant. This reflects the view that the BNE price reflects the decisions of rational investors and in the context of the SEM, recent investment activity has focused on CCGTs. In the table below we provide an overview of the technology choices made by investors for the most recent gas fired combined cycle generation projects in Ireland and Northern Ireland.

Table 3 – Historical technology choices for CCGT plants in Ireland and Northern Ireland

Plant name	Capacity (MW)	GT model	Configuration	Commercial operation date	Fuel type	Cooling type
Dublin Bay	408	GT26	1x1	2002	Dual	Direct
Huntstown 1	343	V94.3A	1x1	2002	Dual	Dry
Coolkeeragh	400	9FA	1x1	2005	Dual	Direct
Tynagh	404	9FA	1x1	2006	Dual	Dry
Huntstown 2	403	M701F	1x1	2007	Dual	Dry
Aghada	435	GT26B2.2	1x1	2010	Dual	Direct
Whitegate	445	9FB	1x1	2010	Dual	Dry
Great Island	464	M701F	1x1	2015	Dual	Direct

Of the eight projects identified above:

- all projects use F class gas turbine technology;
- four projects use direct once through seawater cooling and four use an air cooled condenser; and
- all plants are designed to burn natural gas as primary fuel and distillate fuel oil as secondary fuel.

3.2.2 Overview of current gas turbine technology

Historically, the predominant technology choice has been a single shaft CCGT plant based on an "F class" gas turbine.

We find that the F class gas turbine in single shaft configuration to be a reasonable choice for the reference CCGT plant.

We considered whether investors might choose one of the more efficient H class gas turbines as opposed to the more mature F class models. Examples of H class models include the GE 9HA, the Siemens SGT5-8000H and the Ansaldo GT36. The ISO rating of a single shaft unit based around a H class gas turbine is in excess of 600 MW at ISO conditions. As this exceeds the current largest infeed in the All-Island system at the present time (the EWIC interconnector at 500MW), we did not consider these H class gas turbines should be used as the reference CCGT plant at the present time.

Of the eight projects identified above, three use the model 9F gas turbine, two use the model M701F4 gas turbine, two use the model GT26 gas turbine and one uses the model V94.3A (now SGT5-4000F) gas turbine. Based purely on the fact that the 9F gas turbine has been the model most often installed on recent CCGT plants in the All-Island system, we decided to use the **GE 9F.05** gas turbine as the basis for the reference CCGT calculation. This is purely for the purposes of selecting a representative model for further consideration and is not intended to reflect a preference for a particular manufacturer. The results of a more detailed acquisition level analysis may favour a different manufacturer.

3.2.2.1 EPC cost and performance estimation

The selected CCGT configuration was modelled using the latest updated version of GT PRO and its associated cost estimating program PEACE. The resultant specific EPC cost and net electrical output estimates are presented in Table 4[4]. The technical assumptions underlying this modelling are listed in the section below.

Table 4 – EPC cost estimate and performance for selected CCGT plant option in the Republic of Ireland

Plant Type	**Average Lifetime Output** (MW)	**Average Efficiency** (%, LHV dry basis)	**EPC Cost** (€ million)
CCGT using GE 9FB.05	447.4	57.8	266.6

The outputs of GTPRO and PEACE were cross checked against the Gas Turbine World 2016-17 Handbook and found to be generally consistent.

4 We use Ireland as the basis for assessing EPC costs. The EPC costs for Northern Ireland will be slightly lower due to the lower assumed gird connection voltage level (110kV for Northern Ireland versus 220kV for Ireland).

3.2.2.2 Technical assumptions used for the reference CCGT plant

The following has been built in to the performance and cost models for the CCGT plant option:

- Natural gas fired operation at annual average ambient conditions.
- Coastal site using direct once through seawater cooling. Cooling water intake located at site boundary (shoreline) and cooling water outfall located 500m offshore.
- One single shaft CCGT module based around GE 9FB.05 gas turbine.
- Heat recovery steam generator with 3 pressure levels and Reheat (3PRH).
- Transmission voltage of 110kV for Northern Ireland and 220kV for Ireland.
- Plant designed to burn distillate fuel oil as back up fuel. Distillate storage of 5.0 days at maximum plant load.
- No fogging or inlet air evaporative cooling employed.
- No Selective Catalytic Reduction for NOx control.
- No black-start capability.
- Gas network pressure does not drop below 30 bar. No gas compressors were considered.
- Average lifetime draught losses of 6 and 12.5 mbar for inlet and outlet respectively.
- Average lifetime degradation for power output and efficiency of 2.8% and 1.6% respectively.

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4. CAPITAL AND ANNUAL FIXED COSTS

4.1 Introduction

This section sets out the capital and annual fixed cost estimates associated with the selected reference technologies for Northern Ireland and Ireland. Monetary values are based on 2017 price levels. Where currency conversions (from USD to EUR) have been made we have assumed an exchange rate of 1.12 USD/EUR, which is the average rate to date, according to the data provided by the Bank of Ireland.

4.2 Cost types

In this section we consider:

- Capital costs, which have been sub-divided as follows:
  - EPC contract price and timeframe;
  - Site procurement costs;
  - Electrical interconnection costs;
  - Gas and raw water connection costs (where applicable);
  - Owner's contingency;
  - Financing Fees;
  - Interest During Construction ('IDC');
  - Construction insurance;
  - Up-front costs for initial filling of fuel oil tanks;
  - Project development and O&M mobilisation costs;
  - Commissioning utilities costs;
  - Operating spare parts; and
  - Market accession and participation.
- Annual fixed costs, which have been sub-divided as follows:
  - Trading and admin ;
  - Personnel;
  - Insurance;
  - Fixed maintenance;
  - Fixed fees payable under LTSA;
  - Business rates;
  - Market operator rates;
  - Electricity transmission charges; and
  - Gas transportation charges.

4.3 Capital costs

4.3.1 *EPC contract price*

The EPC contract price estimates for Northern Ireland and Ireland are shown in Table 5.

Table 5 – EPC contract price (exclusive of VAT)

Technology type	**Cost** (€ million)	
	Ireland	**Northern Ireland**
OCGT distillate	93.0	91.6
OCGT dual	92.5	92.0
CCGT dual	266.6	264.6

The above EPC costs assume the project is to be implemented on a full 'turnkey' basis with a single EPC contractor. The EPC cost estimates are based on the OCGT (Siemens SGT5-2000E) and the CCGT (GE 9F.05) choices identified in the previous section. The EPC cost for a project in Ireland is slightly higher than Northern Ireland because of the difference in the assumed voltage connection.

4.3.2 *EPC contract duration*

Our assessment of the construction period for the OCGT plant and CCGT plants are presented in Table 6. These periods are from financial close to hand over of the plant from the EPC contractor to the owner.

Table 6 – EPC cost construction period (months)

Technology type	**Construction period** (months)
OCGT	20
CCGT	30

Different EPC contractor candidates are likely to have slightly different construction schedules, but the above is considered to be a reasonable estimate of what should be achievable. One of the key factors in this regard is the factory ex-works delivery date for the gas turbine, and whether a manufacturing slot is available.

4.3.3 *Site procurement costs*

As in previous years, for both Ireland and Northern Ireland, we have considered that an investor would be able to obtain planning permission to develop on agricultural land, probably close to a relatively unconstrained part of the transmission network. Our assessment of the prices of suitable greenfield sites in Ireland and Northern Ireland are presented in Table 7.

Table 7 – Land prices in Ireland and Northern Ireland

Site location	**Land price** (€/acre)
Ireland	150,000
Northern Ireland	187,500

In the previous BNE price determination, the site procurement cost for Ireland was €150,000 per acre. We have retained this same figure on the basis that we have seen no firm evidence to suggest that there has been a significant rise or fall in land values since developing the 2015 estimate.

For Northern Ireland, we have taken the Irish assumption on site procurement costs as a base and have adjusted for the relative difference in agricultural land values between Northern Ireland and Ireland. Agricultural land in Northern Ireland appears to be 25% higher per acre than in Ireland.

Our assessment of the land area required for each of the technology options considered in the report is presented in Table 8.

Table 8 – Land area requirements for each technology

Technology type	**Require land area** (m^2)
OCGT distillate	19,600
OCGT dual	20,000
CCGT dual	80,000

The dual fuel OCGT requires a slightly larger area than the distillate OCGT due to the requirement for an on-site natural gas above ground installation (containing pipe inspection gauge receiver) and the downstream metering and regulating station (MRS). The additional half day storage of liquid fuel for the distillate scenarios does not impact this position materially.

The site procurement cost for each technology option located in both Ireland and Northern Ireland based on the above land prices and land area requirements is presented in Table 9.

Table 9 – Site procurement costs

Technology type	Cost (€)	
	Ireland	**Northern Ireland**
OCGT distillate	726,489	908,111
OCGT dual	741,315	926,644
CCGT dual	2,965,260	3,706,575

4.3.4 Electrical connection costs

Our assessment of the electrical connection costs for sites located in both Ireland and Northern Ireland is presented in Table 10.

Table 10 – Electrical connection cost

Site location	Cost (€)
Ireland	5,736,000
Northern Ireland	5,701,000

The above costs are based on a notional rural site located within 5 km of an existing transmission system substation and that the site characteristics will permit the connection to be made by overhead line. The transmission system connection voltage is assumed to be 220kV and 110kV for Ireland and Northern Ireland respectively.

The hypothetical connection comprises a 5 km long double circuit overhead line and a two bay extension of existing substation.

For the site in Northern Ireland our approach has been to use the above hypothetical connection design in conjunction with the cost estimates provided in the SONI Transmission Connection Charging Methodology Statement effective from 1st September 2016.

For the site in Ireland our approach has been to use the above hypothetical connection design in conjunction with the cost estimates provided in the 2015 Standard Transmission, Distribution and Operation and Maintenance Charges published by the Commission for Regulation of Utilities (Decision Paper CER/15/013 published 13 Jan 2015).[5]

5 https://www.cru.ie/wp-content/uploads/2015/07/CER15013-2015-Standard-Transmission-Distribution-and-Operation-and-Maintenance-Charges-4.pdf

4.3.5 Raw water connection costs

Our assessment of the raw water connection costs required for each of the technology options considered are presented in Table 11.

Table 11 – Raw water connection costs

Technology type	Cost (€)
OCGT distillate/dual	499,800
CCGT dual	637,000

The above raw water connection costs are based on the cost of installing a new water supply pipeline between the power plant site and the nearest pressurised towns water supply main. The length of this pipeline is assumed to be 1 km.

The water connection cost for the CCGT technology is higher than the OCGT technology due to the requirement for a larger diameter supply pipeline. For a project of this nature the diameter of the supply pipeline is typically sized based on the requirement to refill the on-site fire water storage tank within an 8 hour period as required by National Fire Protection Association ('NFPA') codes. The amount of fire water storage will be higher for CCGT plant than OCGT plant due to the larger fire risks (in particular the larger generator step up transformer and larger distillate fuel oil storage volume). Based on this approach, the pipeline diameter has been estimated to be 4 inches and 6 inches for the OCGT and CCGT technology respectively.

The above costs has been derived using the Thermoflow GTPRO software and associated PEACE module (refer to Section 3.1.4 of this Report).

4.3.6 Gas connection costs

Our assessment of the natural gas connection costs required for each of the technology options considered in the report are presented in Table 12.

Table 12 – Gas connection costs

Technology type	Cost (€)
OCGT distillate	-
OCGT dual	3,677,959
CCGT dual	4,558,785

The above costs are based on a notional rural site located within 2 km of the existing gas transmission network.

For the OCGT technology, the gas connection cost is based on cost data provided in 2010 by Gas Networks Ireland (then known as Bord Gáis Networks). Gas Networks Ireland provided connection prices for three 8 inch pipelines varying in length from 2 km to 3 km. Based on the price information provided by Gas Networks Ireland , the average installed pipeline cost was calculated to be 1,690 €/m (2010 price level). Adjusting for actual inflation over the period 2010-17, this is equivalent to a 2017 price level of 1,839 €/m. We consider this figure represents a reasonable basis for estimating the gas connection cost for the OCGT plant.

The gas connection cost for the CCGT technology is higher than the OCGT technology due to the requirement for a larger diameter supply pipeline. For the CCGT plant the gas connection cost is based on an average installed pipeline cost of 2,280 €/m. This is estimated based on our in house knowledge and price information available in the public domain for similar gas pipeline projects.

The above costs cover connection to the existing gas transmission network, a 2km long buried high grade steel pipeline and an above ground installation with pig receiver located at the power plant site. The natural gas metering and regulating station has been accounted for within the power plant EPC contract price.

4.3.7 Owner's contingency

The Owner's contingency cost estimates for Northern Ireland and Ireland are shown in Table 13.

Table 13 – Owner's contingency

Technology type	Cost (€)	
	Ireland	Northern Ireland
OCGT distillate	4,651,837	4,578,345
OCGT dual	4,627,263	4,599,724
CCGT dual	13,330,851	13,230,851

The project lenders in non-recourse financed project typically require a certain amount of funding to be reserved for contingencies. This Owner's contingency covers such things as project delays due to force majeure events, additional civil works costs due to unexpected sub-terrain, and claims relating to interface problems.

The Owner's contingency has been based on 5% of the EPC contract price which is generally accepted as being sufficient for projects such as this to cover the possible variations and cost increases due to technical reasons.

4.3.8 Financing costs

The Owner's financing cost estimates for Northern Ireland and Ireland are shown in Table 14.

Table 14 – Financing costs

Technology type	**Cost** (€)	
	Ireland	**Northern Ireland**
OCGT distillate	1,860,735	1,831,338
OCGT dual	1,850,905	1,839,890
CCGT dual	5,332,340	5,292,340

We assume financing costs are 2% of the EPC contract price. This is based on our experience of what has been achieved on other similar projects using project financing.

4.3.9 Interest during construction costs

The interest during construction cost estimates for Northern Ireland and Ireland are shown in Table 15.

Table 15 – Interest during construction

Technology type	**Interest during construction cost** (€)	
	Ireland	**Northern Ireland**
OCGT distillate	1,318,240	1,187,000
OCGT dual	1,349,700	1,225,638
CCGT dual	5,692,748	5,163,138

The above costs have been calculated assuming:

- a capital structure of 40/60 debt-equity ratio;
- a lending rate of 2.75% for Ireland and 2.5% for Northern Ireland; and
- a construction period of 20 months and 30 months for the OCGTs and CCGTs respectively.

4.3.10 Construction insurance

The construction insurance cost estimates for Northern Ireland and Ireland are shown in Table 16.

Table 16 – Construction insurance cost

Technology type	Cost (€)	
	Ireland	Northern Ireland
OCGT distillate	837,331	824,102
OCGT dual	832,907	827,950
CCGT dual	2,399,553	2,381,553

We assume construction insurance costs are 0.9% of the EPC contract price. This is based on our experience of what has been achieved on other similar projects.

4.3.11 Initial filling of distillate fuel oil storage tanks

It is necessary to include the cost of fuel which needs to be held to comply with various regulatory policies as part of the capital cost.

In Ireland this cost is driven by the secondary fuel obligation[6]. For gas plants this states:

> *Generating units that expect to operate more than 2,630 hours per year are categorised as higher merit generating units for the purpose of this proposed decision. These units are required to hold stocks equivalent to five days continuous running based on the unit's rated capacity on its primary fuel.*
>
> *Generating units that expect to operate less than 2,630 hours per year are categorised as lower merit generating units for the purpose of this proposed decision. These units are required to hold stocks equivalent to three days continuous running based on the unit's rated capacity on its primary fuel.*

In Northern Ireland this cost is driven by the Fuel Switching Agreement. For gas plants this states:

> *Section 2.2. Quantity of Fuel to be Stored*
>
> *The parties acknowledge and agree that the amount of fuel generators are required to store shall be the fuelling requirement to run each Generating Unit for a continuous period of five days at its maximum rated capacity (the "Required Fuel Level").*

The requirement is 5 days for a dual fuel CCGT plant as it is expected to operate more than 2,630 hours per year. The requirement is 3 days for a dual fuel OCGT plant as it is expected to operate for less than 2,630 hours per year. For the OCGT distillate option which is designed to burn distillate fuel as the primary fuel, we have assumed a requirement to hold stocks equivalent to three and a half days continuous running at rated

6 Secondary Fuel Obligations on Licensed Generation Capacity in the Republic of Ireland, Decision Paper CER/09/001.

capacity. This is consistent with approach taken in previous BNE determinations and we consider it remains a reasonable assumption.

The above requirements are summarised in Table 17.-

Table 17 – Distillate fuel oil stockholding (expressed in days of continuous operation at rated capacity)

Technology type	Days of continuous operation at rated capacity	
	Ireland	Northern Ireland
OCGT distillate	3.5	3.5
OCGT dual	3.0	3.0
CCGT dual	5.0	5.0

Our estimate of the actual volume of fuel oil to be held on site in order to comply with the above requirements is presented in Table 18. These volumes were derived by multiplying the above number of days by the estimated distillate fuel oil consumption rate of each plant. The latter was estimated by modelling the distillate fuel oil operating mode using GT PRO. A 3% contingency was applied to the resulting figure.

Table 18 –Distillate fuel oil storage volumes

Technology type	Litres	
	Ireland	Northern Ireland
OCGT distillate	4,596,890	4,596,890
OCGT dual	3,940,191	6,566,986
CCGT dual	10,791,457	10,791,457

Based on the above our estimate of the initial filling of the fuel oil storage tank cost for Northern Ireland and Ireland are shown in Table 19.

Table 19 – Initial filling of distillate fuel oil storage tank costs

Technology type	Cost (€)	
	Ireland	Northern Ireland
OCGT distillate	1,838,756	2,427,664
OCGT dual	1,576,076	2,080,854
CCGT dual	4,316,583	5,699,076

The above costs are based on the storage quantities stipulated above and a fuel oil price of € 0.4/litre[7]. The excise duty has also been added to the fuel oil price for Northern Ireland.

4.3.12 Project development and O&M mobilisation costs

The project development and O&M mobilisation cost estimates for Northern Ireland and Ireland are shown in Table 20.

Table 20 – Project development and O&M team mobilisation costs

Technology type	**Cost** (€)	
	Ireland	**Northern Ireland**
OCGT distillate	5,582,204	5,494,014
OCGT dual	5,552,716	5,519,669
CCGT dual	15,997,021	15,877,021

Development costs have been estimated based on the assumption that the project will be developed based on project financing. The development costs include the cost of various studies and investigations (including site soil investigation), permits and licenses, engineering fees (including owners engineer for design review and site supervision, etc.), inspection fees, legal advisor, lenders' due diligence costs, insurance advisor, environmental impact assessment report and miscellaneous other owner's administration and development costs.

The O&M mobilisation costs include mobilisation costs under a third party O&M Agreement (for hiring, basic training and payroll cost of the new power plant's operating and maintenance personnel) and also costs for tools, office furniture and computers, forklift truck etc.

We have assumed the combined development and mobilisation costs are 6% of the EPC contract price. This is based on our experience of what has been achieved on other similar projects.

4.3.13 Commissioning utilities cost

The commissioning utilities cost estimates for Northern Ireland and Ireland are shown in Table 21.

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7 We recognise that fuel oil price levels are currently below this level with implied fuel oil prices for power generation in the UK around € 0.3/litre (excluding the fuel excise duty and based on the Quarterly Energy Prices published by BEIS in March 2018). For the purposes of this analysis, we have decided to take a more conservative approach and assume an around 30% higher price for distillate fuel oil.

Table 21 – Commissioning utilities cost

Technology type	Cost (€)	
	Ireland	Northern Ireland
OCGT distillate	2,325,918	2,289,172
OCGT dual	2,313,632	2,299,862
CCGT dual	6,665,426	6,615,426

Commissioning utilities costs include the cost of natural gas, distillate fuel oil and electricity used during the commissioning phase of the project, which are generally the responsibility of the project develop under the EPC contract.

We assume the commissioning utilities costs are 2.5% of the EPC contract price. This is based on our experience of what has been achieved on other similar projects and assumes that revenues received for electricity that is produced by the power plant during testing are sufficient to cover fuel costs from the point that the unit is synchronised to the grid.

The cost of electricity and water during the construction phase and chemical and other consumables (lubricating oil, etc.) during the commissioning phase are included in the EPC contract price.

4.3.14 Operating spare parts

The operating spare parts cost estimates for Northern Ireland and Ireland are shown in Table 22.

Table 22 – Operating spare parts costs

Technology type	Cost (€)	
	Ireland	Northern Ireland
OCGT distillate	1,395,551	1,373,503
OCGT dual	1,388,179	1,379,917
CCGT dual	3,999,255	3,969,255

This cost will cover the spare parts that are required to be held on site:

- Consumable Spares: spares associated with the day-to-day maintenance, inspection and minor overhaul of the plant which requires regular attention, repair or replacement.
- Overhaul Spares: spares associated with planned overhauls (excluding items covered under the Long Term Service Agreement for the gas turbine) to ensure that the Plant can achieve availability or efficiency targets.

We have assumed operating spare parts costs are 1.5% of the EPC contract price. This is based on our experience of what has been achieved on other similar projects. This cost does not cover any strategic spares.

4.3.15 Accession and participation fees

The accession and participation fees are based on the latest SEMO Tariffs and Imperfection Costs statement, dated 7 September 2017. We assume that under I-SEM there will not be any significant changes in those charges.

Table 23 – Accession and participation fees

Technology type	Cost (€)	
	Ireland	Northern Ireland
OCGT distillate	3,654	3,654
OCGT dual	3,654	3,654
CCGT dual	3,654	3,654

4.4 Annual fixed costs

4.4.1 Trading and administrative costs

The trading and admin cost estimates for Northern Ireland and Ireland are shown in Table 24.

Table 24 – Trading and administrative cost estimates

Technology type	Cost (€)	
	Ireland	Northern Ireland
OCGT distillate	744,294	732,535
OCGT dual	740,362	735,956
CCGT dual	2,132,936	2,116,936

Trading and admin costs include trading and settlement overhead costs, bank fees, security expenses, public relations, legal fees, freight and import duties, auditing fees, safety equipment, office equipment expenses, and other miscellaneous expenses.

We assume annual trading and admin costs are 0.8% of the EPC contract price. This is based on our experience of what has been achieved on other similar projects.

4.4.2 Personnel costs

The personnel cost estimates for Northern Ireland and Ireland are shown in Table 25.

Table 25 – Personnel cost estimates

Technology type	Cost (€)
OCGT distillate/dual	780,000
CCGT dual	3,166,000

Personnel costs assume the plant is operated and maintained by a third party O&M company and cover salary and wages, bonus payments, shift premiums, pension contributions, social security contributions and O&M company profit.

For the OCGT technology we have assumed an O&M team comprising 10 full time employees and an average cost of €78k per employee. For the CCGT technology we have assumed an O&M team comprising 38 full time employees and an average cost of €83k per employee. The slightly higher cost per employee for the CCGT plant is based on the CCGT plant having more senior managers within the organisational structure.

4.4.3 Insurance

The insurance cost estimates for Northern Ireland and Ireland are shown Table 26.

Table 26 – Insurance cost estimates

Technology type	Cost (€)	
	Ireland	Northern Ireland
OCGT distillate	558,220	549,401
OCGT dual	555,272	551,967
CCGT dual	1,599,702	1,587,702

The annual insurance covers the O&M period insurances for general liability, machinery breakdown and business interruption for the power plant.

We assume insurance costs are 0.6% of the EPC contract price. This is based on our experience of what has been achieved on other similar projects.

4.4.4 Fixed Maintenance Cost

The fixed maintenance cost estimates for Northern Ireland and Ireland are shown in Table 27.

Table 27 – Fixed maintenance cost estimates

Technology type	Cost (€)	
	Ireland	Northern Ireland
OCGT distillate	465,184	457,834
OCGT dual	462,726	459,972
CCGT dual	1,333,085	1,323,085

The fixed maintenance cost covers routine and preventative maintenance activities including consumables (filters, fuses, bulbs, gaskets, pump mechanical seals, pump / motor bearings, lubricating oil changes, etc.).

We assume fixed maintenance costs are 0.5% of the EPC contract price. This is based on our experience of what has been achieved on other similar projects.

4.4.5 Fixed costs under LTSA

Our estimate of the fixed costs payable under the Long Term Service Agreement (LTSA) for Northern Ireland and Ireland are shown in Table 28.

Table 28 – Fixed cost payable under LTSA

Technology type	Cost *(m€)*
OCGT distillate/dual	600,000
CCGT dual	1,710,000

The above cost assumes that the plant Owner will enter into a Long Term Service Agreement (LTSA) for the gas turbine which will fix the cost of these parts over the life of the project. Under this agreement the LTSA Contractor will typically be the exclusive provider of parts and labour for the planned maintenance for the gas turbine.

Gas turbine manufacturers typically recommend a maintenance schedule involving combustion inspections, hot gas path inspections and major inspections. The intervals for each type of inspection are based on independent counts of either unit starts or unit operating hours. The exact interval varies from manufacturer to manufacturer. Some representative figures are shown in the table below.

Table 29 – Typical Gas Turbine Maintenance Intervals

Planned maintenance action	Hours	Starts
Combustion inspection	8,000	450
Hot gas path inspection	24,000	900
Major inspection	48,000	2400

For an OCGT operating as a low merit peaking plant, it is typically the number of starts that are expected to be the determining factor for when scheduled maintenance is required to be carried out. In contrast for a high efficiency CCGT operating as a high merit base load plant, it is the number of operating hours that are expected to be the determining factor for when scheduled maintenance is required to be carried out.

For the purposes of the maintenance cost determination, we have assumed that the OCGT plant will operate for 500 operating hours and 150 starts per annum and that the CCGT plant will operate for 8000 hours and 50 starts per annum.

The fees payable to the LTSA contractor are typically structured as a fixed component (€ per annum) and a variable component (€ per operating hour). The exact fee structure varies from manufacturer to manufacturer and depends on the contractual arrangements achieved in negotiation between the plant owner and the LTSA contractor. Based on our experience of other similar projects, we have assumed that the fixed fee payable under the LTSA is 30% of the total annual levelised LTSA cost.

4.4.6 Business rates

Business rates are a (commercial) tax paid to the local authorities in Ireland and the regional authorities in Northern Ireland.

The level of the business rates in Ireland depends on the value of the property and a valuation multiplier (Annual Rate on Valuation) that is county specific. Based on the latest Valuation Office data, we have estimated an average multiplier of 66. The assumption for the value of the BNE peaking plant of 115 EUR/MW as per the previous BNE determination appears to be in line with valuations of existing power plants. We use a value of 117 EUR/MW to account for inflation.

The assumed business rates for Northern Ireland are based on the Rateable Net Annual Value (‘NAV’) as defined by the Valuation (Electricity) Order (Northern Ireland) 2003[8] and the total non-domestic rates for 2017/2018[9]. Table 30 presents our assumed business rates for the reference technologies for Ireland and Northern Ireland.

8 Valuation (Electricity) Order (Northern Ireland) 2003, UK legislation.

9 Poundages 2017-2018, Department of Finance.

Table 30 – Business rates

Technology type	Cost (€)	
	Ireland	**Northern Ireland**
OCGT distillate	1,468,724	623,484
OCGT dual	1,533,589	651,020
CCGT dual	3,454,604	2,258,417

4.4.7 *Market operator rates*

Table 31 provides for the estimated market operator fees in accordance with the latest SEMO Fixed Generator charge[10] of €39/MW.

Table 31 – Market operator fees

Technology type	Cost (€)	
	Ireland	**Northern Ireland**
OCGT distillate	7,418	7,418
OCGT dual	7,745	7,745
CCGT dual	17,447	17,447

4.4.8 *Electricity transmission charges*

The GTUoS are assumed to remain equal (in real terms) to the existing average levels for Ireland and Northern Ireland, as determined by Eirgrid and SONI for 2017/18 in the Generation Transmission Use of System Tariffs report. Table 32 presents the total electricity transmission charge for each reference technology.

Table 32 – Electricity transmission charges

Technology type	Cost (€)	
	Ireland	**Northern Ireland**
OCGT distillate	1,184,432	1,054,906
OCGT dual	1,236,742	1,101,495
CCGT dual	2,785,918	2,481,258

[10] Single Electricity Market, SEMO Tariffs and Imperfection Costs, 7 September 2017.

4.4.9 Gas transportation charges

Gas transportation charges in Ireland and Northern Ireland are relatively high. A generating unit operating baseload/mid-merit would typically attempt to buy long-term gas capacity rights, and the associated cost would be treated as an annual fixed cost. A peaking plant, on the other hand, would be better off buying rights within-day. This cost then becomes a 'variable' cost and should not be included as part of the annual fixed costs, as it can be recovered through market bidding. This is also reflected in all previous BNE determination where the gas transportation charges were assumed to be zero.

Table 33 shows the estimated cost for the reference technologies. The gas transportation cost for an OCGT is assumed to be zero. For a CCGT we assume that it buys 80% of the required gas capacity through long term rights. The lower gas transportation cost for Northern Ireland is a result of a lower entry and exit fees. These charges are based on entry and exit fees of €359.2 per peak day MWh and €402.08 per peak day MWh for Ireland[11] and entry and exit fees of £222.3/kWh/day for Northern Ireland[12].

Table 33 – Gas transportation charges

Technology type	**Cost** (€)	
	Ireland	**Northern Ireland**
OCGT distillate	-	-
OCGT dual	-	2,390,551
CCGT dual	12,569,733	10,778,421

11 GNI Transmission Tariff for Gas Year 2017/18.

12 NI Forecast Postalised System Transmission Tariffs 2017/18.

4.5 Summary

The tables below summarise our findings for capital and annual fixed costs.

Table 34 – Capital cost estimates (€ million)

Jurisdiction	Ireland			Northern Ireland		
Technology	**OCGT distillate**	**OCGT dual**	**CCGT**	**OCGT distillate**	**OCGT dual**	**CCGT**
EPC costs	93.0	92.5	266.6	91.6	92.0	264.6
Site procurement cost	0.7	0.7	3.0	0.9	0.9	3.7
Electrical connection costs	5.7	5.7	5.7	5.7	5.7	5.7
Water connection costs	0.5	0.5	0.6	0.5	0.5	0.6
Gas connection costs	0.0	3.7	4.6	0.0	3.7	4.6
Owners contingency	4.7	4.6	13.3	4.6	4.6	13.2
Financing costs	1.9	1.9	5.3	1.8	1.8	5.3
Interest during construction	1.3	1.4	5.7	1.2	1.2	5.2
Insurance	0.8	0.8	2.4	0.8	0.8	2.4
Initial fill of fuel oil tanks	1.8	1.6	4.3	2.4	2.1	5.7
Project development	5.6	5.6	16.0	5.5	5.5	15.9
Commissioning utilities	2.3	2.3	6.7	2.3	2.3	6.6
Operating spares	1.4	1.4	4.0	1.4	1.4	4.0
Accession fees	0.0	0.0	0.0	0.0	0.0	0.0
Participation fees	0.0	0.0	0.0	0.0	0.0	0.0
Total	**119.8**	**122.7**	**338.3**	**118.7**	**122.6**	**337.5**

Table 35 – Annual fixed cost estimates (€ million)

Jurisdiction	Ireland			Northern Ireland		
Technology	**OCGT distillate**	**OCGT dual**	**CCGT**	**OCGT distillate**	**OCGT dual**	**CCGT**
Trading and admin	0.7	0.7	2.1	0.7	0.7	2.1
Personnel	0.8	0.8	3.2	0.8	0.8	3.2
Insurance	0.6	0.6	1.6	0.5	0.6	1.6
Fixed maintenance	0.5	0.5	1.3	0.5	0.5	1.3
Fixed fee under LTSA	0.6	0.6	1.7	0.6	0.6	1.7
Business rates	1.5	1.5	3.5	0.6	0.7	2.3
Market operator rates	0.0	0.0	0.0	0.0	0.0	0.0
Electricity transportation charges	1.2	1.2	2.8	1.1	1.1	2.5
Gas transportation charges	0.0	0.0	12.6	0.0	2.4	10.8
Total	**5.8**	**5.9**	**28.8**	**4.8**	**7.3**	**25.4**

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5. ENERGY MARKET AND SYSTEM SERVICES REVENUES

To arrive at the net CONE we need to subtract non-Capacity Market revenue streams from the gross CONE. In addition to income from the Capacity Market, a capacity provider operating in I-SEM would be capturing:

- revenues from the energy market(s):
  - A generating unit is expected to capture a certain amount of operating margin, commonly referred to as inframarginal rent, from selling electricity into different ex-ante markets and the balancing market.
- income for the provision of DS3 System Services:
  - DS3 System Services are procured by the TSOs and potential providers capture a relevant payment.

5.1 Inframarginal rent

The inframarginal rent can be defined as the electricity market revenue net of the short-run cost of operation. For determining the expected inframarginal rent for a generating unit we need to take a view on:

- the expected operating pattern of the new entrant:
  - an OCGT would, by definition, be assumed to be operating as a peaking unit;
  - a new entrant CCGT would be expected to run in a baseload/mid-merit fashion in the short to medium term.
- electricity price formation:
  - the evolution of commodity and CO_2 prices are key drivers of the resulting electricity prices; and
  - the impact of the Administered Scarcity Price (‘ASP’) function and the strike price of the Reliability Option (‘RO’) contracts on spot price formation need to be accounted for.

5.1.1 Inframarginal rent for an OCGT

In all previous decisions for the BNE price determination as part of the prior CPM, the inframarginal rent for a peaking plant has been based on capturing the assumed price cap (equal to 1000 EUR/MWh for SEM) in 8 hours in a given year. For the T-1 auction for Capacity Year 2018/19, the SEM Committee decided to:

- Take into account the fact that the de-rated capacity of the new entrant would be covered under the RO contract and would be subject to ‘paying back’ the difference between the resulting spot price and the strike price, whereas part of the capacity that is not covered under the RO contract would be fully exposed to the spot price.
- Assume an additional 4 hours of ‘partial’ operation of the peaking plant in addition to the 8 hours corresponding to the statutory security standard.

Consistent with the assumption of 8 hours of full ASP and 4 hours of partial ASP, as decided in SEM-17-022, the expected inframarginal rent for an OCGT is:

$$IMR_{GT} = [RO\ DIFFERENCE\ PAYMENT\ FOR\ RO\ CAPACITY] + [ASP\ PAYMENT\ FOR\ NON-RO\ CAPACITY] + [CAPTURED\ IMR\ FOR\ RO\ CAPACITY] =$$

$$DERATING_{GTi} \times 8 \times OUTAGE_{GT} \times (SP - FULL\ ASP) + (1 - DERATING_{GTi}) \times 8 \times (1 - OUTAGE_{GT}) \times (FULL\ ASP - INC_{GT}) + DERATING_{GTi} \times 8 \times (1 - OUTAGE_{GT}) \times (SP - INC_{GT}) + DERATING_{GTi} \times 4 \times OUTAGE_{GT} \times (SP - PARTIAL\ ASP) + (1 - DERATING_{GTi}) \times 4 \times (1 - OUTAGE_{GT}) \times (PARTIAL\ ASP - INC_{GT}) + DERATING_{GTi} \times 4 \times (1 - OUTAGE_{GT}) \times (SP - INC_{GT})$$

where

$DERATING_{GTi}$ is the de-rating factor as determined by the TSOs for the corresponding technology and nameplate capacity range.

$OUTAGE_{GT}$ is the forced outage rate, assumed to be equal to the capacity de-rating for the smallest capacity range [0-1MW] as provided by the TSOs.

INC_{GT} is the incremental operating cost of a GT, assumed to be equal to 212.58 €/MWh, in line with the assumption used for the 2018/19 BNE inframarginal rent.

SP is the Strike Price of the Reliability Option contract.

$FULL\ ASP$ is the full Administered Scarcity Price assumed to be equal to the current Euphemia price cap of 3000 €/MWh.

$PARTIAL\ ASP$ is assumed to be half the value of the full Administered Scarcity Price.

SP is the Reliability Option Strike Price assumed to be equal to the DSU floor price of 500 €/MWh.

The calculation implied by the above formula is presented in Table 36. The non-RO capacity share is the part of the capacity of the peaking plat that is not covered by the RO contract and is equal to the capacity de-rating. The RO capacity share is the part of the capacity that is covered by the RO contract and is equal to the de-rating factor. The size of the selected peaking plant falls within the range 191-200MW with a proposed de-rating factor of 90.9%[13].

13 http://www.sem-o.com/ISEM/General/Initial%20Auction%20Information%20Pack.pdf

Table 36 – Calculation of inframarginal rent for reference peaking plant (assuming full ASP of 3,000 EUR/MWh)

I-SEM ASP assumption	Activity state	Capacity share	Cashfow (€/MW - installed/year)
	Outage (7.4%)	Non RO	0
8 hours @ 3,000 €/MWh	Outage (7.4%)	RO	-1,345
	Active (92.6%)	Non RO	1,879
	Active (92.6%)	RO	1,935
	Outage (7.4%)	Non RO	0
4 hours @ 1,500 €/MWh	Outage (7.4%)	RO	-269
	Active (92.6%)	Non RO	434
	Active (92.6%)	RO	968
Total			**3,602**

The resulting inframarginal rent for a reference peaking plant is **3.602 €/kW - installed** in nominal terms. This is in line with an assumption that the full ASP value and the DSU floor price do not rise in line with inflation. On this basis, the inframarginal rent is expected to decrease in real terms.

We recognise that our calculation assumes that the value of full ASP continues to be equal to 3,000 €/MWh. This is subject to change and the full ASP could be set, in the future, at the level of the Value of Lost Load ('VoLL'). Assuming a VoLL of 11,000 €/MWh, the estimated inframarginal rent for a peaking plant (based on the above methodology) would increase to around 5 €/kW. The step-by-step calculation is presented in Table 37.

Table 37 – Calculation of inframarginal rent for reference peaking plant (assuming full ASP of 11,000 €/MWh)

I-SEM ASP assumption	Activity state	Capacity share	Cashfow (€/MW - installed/year)
	Outage (7.4%)	Non RO	0
8 hours @ 11,000 €/MWh	Outage (7.4%)	RO	-5,650
	Active (92.6%)	Non RO	7,272
	Active (92.6%)	RO	1,935
	Outage (7.4%)	Non RO	0
4 hours @ 5,500 €/MWh	Outage (7.4%)	RO	-1,345
	Active (92.6%)	Non RO	1,782
	Active (92.6%)	RO	968
Total			**4,962**

5.1.1.1 Recommendation

We have opted to determine the inframarginal rent for the reference peaking plant in a way that reflects current policy choices (and in line with previous SEM Committee determinations). We appreciate the value of full ASP may change in the future, and this would have an impact on the expected inframarginal rent for the reference peaking plant. However, given the current choice for the full ASP, we recommend to assume an inframarginal rent of **3.602 €/kW – installed** in nominal money terms for the reference peaking plant. We expect the decision about the inframarginal rent for the reference peaking plant to be updated (if needed) to reflect any changes linked to the ASP as part of other relevant consultations.

5.1.2 Inframarginal rent for a CCGT

A new entry CCGT is expected to operate at significantly higher load factors, and capture higher inframarginal rent when compared to a peaking plant and so the 'ASP-only' calculation applied to the peaking plant is not appropriate for a CCGT. The operating pattern and the price formation are the key drivers of the expected inframarginal rent for a CCGT. This means that the assumed commodity prices, alongside assumptions with regards to demand, capacity exit and technology costs will have an impact on the projected wholesale price levels.

For the purposes of the net CONE determination we opt for a simple and transparent approach for defining the level of inframarginal rent. We recognise that this comes at the expense of greater accuracy that would have been achieved with the use of a sophisticated electricity market model and a 'captured' price analysis, but, at this stage, feel that a simple approach can help deliver the required level of insight.

Due to its relative higher efficiency when compared to an average CCGT in the All-Island fleet, a new entry CCGT:

- is expected to be in a more advantageous position in the merit order running ahead of other existing CCGTs:
  - It would most likely be only at high wind periods that a new entry CCGT is not operating at full load.
- when it is 'running' it would be capturing the highest inframarginal rent when compared to all other CCGTs on the system:
  - Its inframarginal rent would be at least equal to the incremental cost difference implied by the efficiency difference between the new entry CCGT and a less efficient existing CCGT.

When it comes to the expected load factor, it is difficult to envisage a set of market conditions (within reason) that would suggest any operating pattern other than mid-merit/baseload for a new entry CCGT in I-SEM. We, therefore, assume an average load factor within the range 65%-75% for the reference CCGT plant over the entire period 2022/23 to 2031/32 (i.e. over the 10-year period of the RO contract)[14].

When it comes to its average variable cost we explore a set of gas and CO_2 prices, based on the 2017 BEIS CO2 and fuel assumptions, for determining its average variable operating cost. Similarly, we can define the variable operating cost of a less efficient existing CCGT. We define the variable operating cost of a CCGT as follows:

14 We assume a 75% load factor in the first year of operation gradually declining (linearly) to 65% in the tenth year of operation.

$$VOC = \frac{Gas}{Eff} + \frac{CO_2 \times GC_{gas}}{Eff} + VOWC$$

where

VOC is the variable operating cost.

Gas is the gas price in €/MWh of gas in HHV terms.

Eff is the full-load HHV efficiency of the CCGT.

CO_2 is the CO_2 price in €/tonne.

GC_{gas} is the carbon content of gas in tonnes/MWh, and is summed to be equal to 0.181764 tonnes/MWh.

$VOWC$ are the variable other works costs of a CCGT.

The calculated variable operating cost for the reference (new entry) CCGT and a 'generic' existing CCGT for the assumed gas and CO_2 prices are presented in Table 38 for 2022/23 (the first year of operation) and for 2031/32 (the last year of operation under the capacity contract). The difference in efficiency suggests a difference in variable operating costs of 3.1 €/MWh and 5.7 €/MWh in 2022/23 and 2031/32 respectively. Assuming that, when the reference new entry CCGT is operating the wholesale price is set, on average, at the level of a 'generic' existing CCGT, the difference in variable operating cost would represent the captured inframarginal rent.

However, quasi-fixed costs (start-up and no-load) and their impact on price formation should also be accounted for. The resulting average wholesale price when the reference CCGT is operating can then be defined as:

$$WP = VOC_{existing} + UPLIFT$$

where

WP is the average wholesale price at times when the reference new entry CCGT is operating

$VOC_{existing}$ is the variable operating cost of a generic 'existing' CCGT with an HHV full load efficiency of 48%

$UPLIFT$ is the assumed mark-up to reflect quasi-fixed costs in the wholesale price formation

The uplift in the SEM averaged at 6.3 €/MWh in 2016. For the purposes of our analysis, the impact of quasi-fixed costs on the wholesale price under I-SEM is assumed to be less pronounced. We assume that the mark-up in the wholesale price as a result of the indirect inclusion of quasi-fixed costs in market bids under I-SEM is around 30% lower than the level observed in 2016. This means an uplift of 4.3 €/MWh.

With the inclusion of this 'uplift', the calculated average inframarginal rent over periods of operation for the reference (new entry) CCGT rises to 7.4 €/MWh in 2022/23 and 10 €/MWh in 2031/32. We arrive at the total implied inframarginal rent for a reference new entry CCGT by combining the per MWh difference between the variable operating cost of the reference new entry CCGT and the average captured wholesale price with the assumed load factor. The results of this analysis are presented in Table 38. All monetary values in the table below are in real 2017 money.

Table 38 – Implied inframarginal rent for a reference new entry CCGT (real 2017)

	2022/23	**2031/32**
CO_2 (€/tonne)	7.9	48.1
Gas (€/MWh)	17.3	26.1
VOWC (€/MWh)	2.5	2.5
Variable operating cost of reference CCGT (52.1%)[15]	38.5	69.4
Variable operating cost of 'generic' existing CCGT (48%)	41.5	75.1
Uplift (€/MWh)	4.3	4.3
Captured wholesale price (€/MWh)	45.8	79.4
Assumed load factor	75%	65%
Implied inframarginal rent (€/kW - installed)	**48.4**	**57.0**

We recognise that the above analysis has limitations and various assumptions are made:

- the expected load factor is an assumption and not based on detailed market scheduling modelling:
  - however, a load factor of more than 65% for the first ten years of operation for new entry CCGT commissioned in the early 2020s in I-SEM is broadly in line with our own independent expectations.
- we assume there is no mark-up to reflect scarcity in the wholesale prices and as such the captured wholesale price (based on our analysis above) may be underestimated.

Similarly to the reference peaking plant, we also need to consider the impact of the ASP function on captured inframarginal rent for the reference new entry CCGT. We use the same formula set out in section 5.1.1, replacing the different parameters with the values applicable for the reference CCGT. The marginal de-rating factor for a CCGT of that size is 87.2%. However, the outage rate is assumed to be again 7.4% (equal to the de-rating factor of the smallest unit of that specific technology group). The results of the calculations are presented in Table 39 for 2022/23 and Table 40 for 2031/32.

15 For the new entrant CCGT, we assume that quasi-fixed costs are negligible (due to low number of starts and low number of operating hours at below full load).

Table 39 – Calculation of 'additional' inframarginal rent for reference CCGT (assuming full ASP of 3,000 EUR/MWh) for 2022/23

I-SEM ASP assumption	Activity state	Capacity share	Cashfow (€/MW – installed/year)
	Outage (7.4%)	Non RO	0
8 hours @ 3,000 €/MWh	Outage (7.4%)	RO	-1,291
	Active (92.6%)	Non RO	2,792
	Active (92.6%)	RO	2,873
	Outage (7.4%)	Non RO	0
4 hours @ 1,500 €/MWh	Outage (7.4%)	RO	-258
	Active (92.6%)	Non RO	610
	Active (92.6%)	RO	1,437
Total			**6,164**

Table 40 – Calculation of 'additional' inframarginal rent for reference CCGT (assuming full ASP of 3,000 EUR/MWh) for 2031/32

I-SEM ASP assumption	Activity state	Capacity share	Cashfow (€/MW – installed/year)
	Outage (7.4%)	Non RO	0
8 hours @ 3000 €/MWh	Outage (7.4%)	RO	-1,291
	Active (92.6%)	Non RO	2,752
	Active (92.6%)	RO	2,601
	Outage (7.4%)	Non RO	0
4 hours @ 1500 €/MWh	Outage (7.4%)	RO	-258
	Active (92.6%)	Non RO	610
	Active (92.6%)	RO	1,300
Total			**5,715**

This additional cashflow would be over and above the implied inframarginal rent as presented in Table 38. To avoid double-counting we have replaced the incremental cost of the reference CCGT with the variable operating cost of the 'generic' CCGT, as presented in Table 38, in the formula for defining the 'ASP-linked' inframarginal rent. This means we are only counting for inframarginal rent arising from the ASP function being 'triggered' that has not already been accounted for as part of differences in variable operating costs.

The resulting inframarginal rent is **54.5 €/kW in 2022/23** and **62.7 €/kW in 2031/32 in real 2017 money terms**.

The calculation of the 'additional' inframarginal rent (as a result of the ASP) is based on the current choices with regards to ASP. We recognise that other decisions relating to ASP (and which will be consulted separately during 2018) may affect the expected inframarginal rent and, as a result, the net CONE. We expect the decision about the net CONE to be updated to reflect any changes linked to ASP.

5.1.2.1 Recommendation

Based on our analysis, we propose to use an expected inframarginal rent of **54.5 €/kW in 2022/23 rising linearly up to 62.7 €/kW in 2031/32 in real 2017 money terms** for a reference new entry CCGT. Post 2031/32, we propose to assume that the inframarginal rent decreases by 5% every year to reflect the entry of newer, more efficient units on the system and decreasing load factor for the reference CCGT.

5.2 System Services revenues

Provision of System Services is currently incentivised through the DS3 System Services interim tariffs. These replaced the Harmonised Ancillary Services ('HAS') arrangements, previously in place until September 2016. Remuneration is on the basis of regulated tariffs, at a uniform rate across all trading periods in a year, and all available volumes with a DS3 System Services contract receive a relevant payment. The main difference between the current arrangements and the previous HAS arrangements is the introduction of some new System Services and a more transparent procurement process.

The SEM Committee has indicated that the TSOs should continue to determine regulated tariffs and offer DS3 System Services contracts in the short term under regulated arrangements, while alternative procurement solutions are being put in place[16].

In the coming years, and more importantly, in Capacity Year 2022/23, the DS3 System Services procurement process may have been replaced by an alternative solution, but for the purposes of the determination of the net CONE, we need to take a view with regard to the expected DS3 System Services income captured by the chosen reference technologies. We therefore use the DS3 enduring tariff arrangements as the starting point.

The TSOs have recently made a recommendation on the design of the enduring regulated tariffs and the associated scalars[17]. The proposals include:

- a set of base tariff rates as the baseline for the duration of the enduring regulated tariff arrangements; and
- the introduction of a set of ('stepped') temporal scalars to be applied to the different System Services at times when the System Non-Synchronous Penetration ('SNSP') exceeds the 60% threshold.

These base tariffs and scalars have been approved by the SEM Committee[18]. As part of its analysis, the TSOs have provided for the implied average annual revenue from regulated tariffs per technology type under two scenarios ('Enhanced' and 'New Providers') with the use of the (preferred) 'stepped' temporal scalar design. These annual

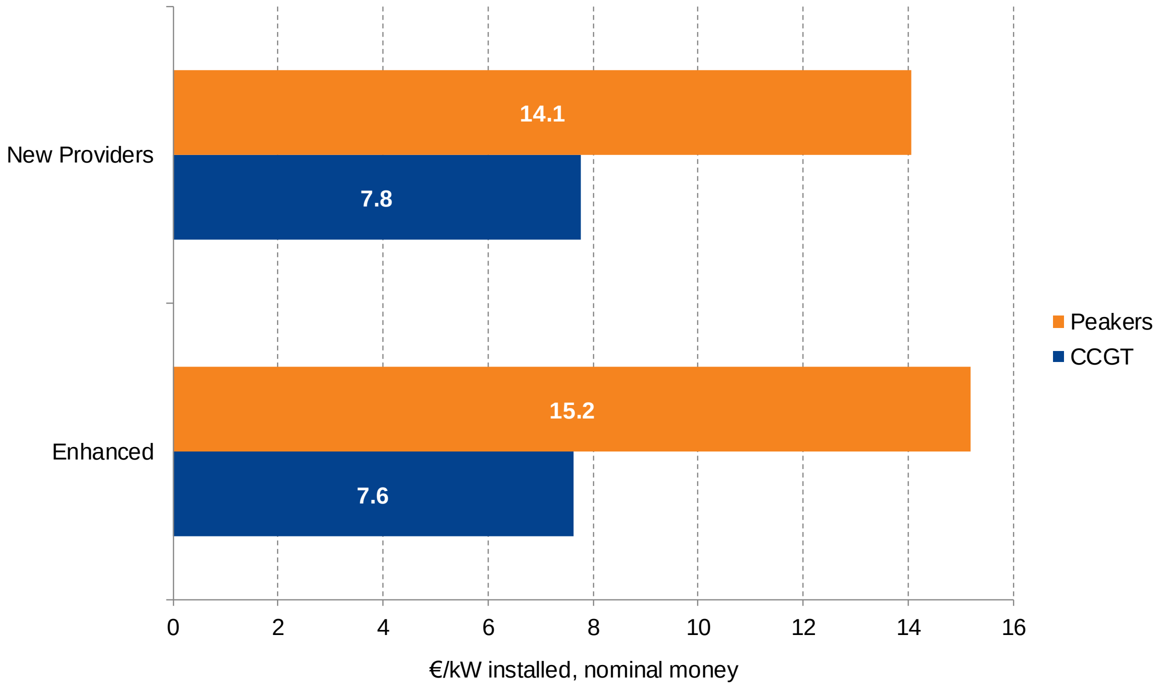
16 SEM-17-017, SEM Committee Information Paper on DS3 System Services Future Programme Approach, March 2017.

17 DS3 System Services Tariffs for Regulated Arrangements, Recommendations Paper, 23 October 2017, Eirgrid & SONI

18 SEM-17-080, SEM Committee Decision, DS3 System Services Tariffs and Scalars, 24 October 2017

revenues are expressed in €/kW[19] (of installed capacity) and reflect the average captured income of the entire technology portfolio for Capacity Year 2019/20. Different generating units will obviously have different captured revenues depending on their capabilities and operating patterns. The average value across all scenarios for a 'generic' CCCT and peakers are presented in Figure 3.

Figure 3 – Peaking plant and CCGT DS3 System Services revenue in 2019/20



In the TSOs analysis, the expenditure cap is reached only in the 'New Providers' scenario and in the 'Enhanced' scenario the total expenditure is below the cap.

The OCGT and CCGT expected income range from 14.1 €/kW to 15.2 €/kW and from 7.6 €/kW to 7.8 €/kW across the two scenarios, respectively. Our understanding is that the expenditure cap of €235 million for DS3 System Services will not be increased post 2019/20 to reflect inflation, and, on that basis, we assume that the DS3 System Services income remains at the same level in future Capacity Years in nominal terms (but decreases in real terms).

A new entrant is likely to have more advanced System Services capabilities and be better positioned in the merit order when compared to a 'typical'[20] unit of the generating fleet. This means its captured System Services revenue may well be greater than that of a 'typical' unit.

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19 We understand these monetary values provided by the TSOs to be expressed in nominal terms.

20 As 'typical' unit here we assume a generating unit of a specific technology class that has the capabilities and captures a level of DS3 income equivalent to the average of the existing fleet on the All-Island system.

However, for the purposes of the net CONE determination we propose to follow a more conservative approach and use the average across all cases for each technology type. This choice recognises the current uncertainty with regards to the future System Services revenues.

5.2.1 Recommendation

Based on the above, we propose to use a value of **7.7 €/kW** – **installed** for a CCGT and a value of **14.6 €/kW** – **installed** for a peaking plant in nominal money terms as the expected DS3 System Services income for a new entrant reference plant. These are representative of the current expectations for the revenues available for a 'typical' peaking plant and CCGT under the DS3 System Services.

6. COST OF CAPITAL

6.1 Approach – estimating the cost of capital

The cost of capital associated with a project is the return an investor would require for providing funds to finance such project. It is effectively the level of return that would appropriately compensate for the riskiness of the investment.

Projects are typically financed through a combination of debt and equity. Debt and equity holders will not necessarily seek the same return and the 'average' cost of capital will reflect these different levels of return and the share of debt and equity employed. This 'blended' cost of capital is commonly referred to as the Weighted Average Cost of Capital (WACC) and, at its simplest, is formulated as:

$$WACC = \frac{D}{V} * R_d + \frac{E}{V} * R_E$$

where D = value of debt;

V = total value of financing (debt and equity);

R_d = cost of debt; and

R_E = cost of equity.

There is extensive literature dealing with the determination of the WACC for regulated assets, as well as for the purposes of setting a reserve price for capacity markets (though not as extensive as for price controls of regulated assets). Defining the individual parameters that make up the WACC is the most common approach and has been adopted in various markets including:

- the BNE price for the SEM CPM[21];
- the net CONE in PJM[22]; and
- the net CONE in ISO-NE[23].

The above list is not exhaustive. However, it includes some of the most established capacity markets that have used such an approach. Great Britain ('GB') is an example where this (more detailed) WACC approach was not followed. Instead, in GB, the discount rate (which can be thought of as approximately equivalent to the WACC) for converting the capex into an annuity, was based on survey results[24].

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21 Cambridge Economic Policy Associates Ltd in association with Ramboll - Costs of a Best New Entrant Peaking Plant for the Calendar Year 2016.

22 The Brattle Group - Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM.

23 The Brattle Group - Cost of New Entry Estimates in ISO-NE.

24 DECC Background on setting Capacity Market parameters.

To ensure consistency with the approach that has been used in Ireland and Northern Ireland in the past and in line with US capacity markets, we have opted to continue using the detailed WACC calculation.

There are two important topics that need to be addressed when defining the WACC for the reference technologies:

- the treatment of inflation:
  - Who bears the risk of inflation? Will an ex-ante expectation of inflation be included, with the WACC defined in nominal terms, or will there be some form of inflation-indexation with the WACC defined in real terms?
- the treatment of taxation:
  - Should the WACC account for the cost of taxation (pre-tax WACC) or should taxation be included as a separate cost item (post-tax WACC)?

The treatment of inflation and taxation are discussed in the following sections.

6.1.1 Estimating the cost of debt

Unlike the cost of equity, the cost of debt can be directly observed from market data. The interest payable on loans can be a good indicator, where such data are available. Alternatively, corporate bond yields can be used as a measure for the cost of debt.

In this report we provide a range for the cost of debt. We have opted to collect market evidence available and choose a reasonable debt premium (in line with the market evidence) to be applied to the risk-free rate, and have also accounted for regulatory precedent when defining our range for the cost of debt.

6.1.2 Estimating the cost of equity

The Capital Asset Pricing Model (CAPM) is the most commonly used tool for estimating the cost of equity. There are several other approaches, such as arbitrage pricing theory and the Fama-French model, but we do not see any reason for moving from the CAPM for this review. Stakeholders are already familiar with the CAPM and as this model is used in other reserve price determinations, this will allow for direct comparisons.

The formulation of the CAPM is as follows:

$$CoE = r_f + \beta_{Equity} * ERP$$

where CoE = cost of equity;

r_f = risk-free rate;

ERP = equity risk premium for the market portfolio (i.e. the return over the risk-free rate an investor would expect for their equity); and

β_{Equity} = equity beta, a measure of non-diversifiable risk of the security relative to the market portfolio.

6.1.3 Treatment of taxation

A pre-tax WACC has been calculated by making an adjustment to the cost of equity based on tax rates in each jurisdiction. This removes the requirement to allow for taxation costs in this calculation and is consistent with the approach taken by the RAs in previous determinations.

6.1.4 Treatment of inflation

The choice between a nominal and a real WACC depends on the context in which it is applied:

- If cash flows are forecasted in nominal money terms then a nominal WACC should be used.
- If cash flows are determined in real money terms and there is a form of inflation indexation then a real WACC should be used.

The two approaches are in theory equal, assuming that inflation is in line with the ex-ante expectation. The real question is who should bear the inflation risk? If there is a form of inflation indexation to the capacity market clearing price, then the project is protected from movements in inflation. Otherwise, investors would need to bear the risk of inflation, and this may have an impact on the perceived risk (and consequently on the cost of capital).

In this report, we present both a real WACC, assuming full inflation indexation, and the corresponding nominal WACC. We convert the real WACC to the nominal WACC with the Fisher equation:

$$WACC_{real} = \left(\frac{(1 + WACC_{nominal})}{(1 + i)}\right) - 1$$

where

$WACC_{real}$ is the real WACC;

$WACC_{nominal}$ is the nominal WACC; and

i is the inflation rate.

However, we note that the SEM Committee has decided there will be no inflation indexation for 10-year contracts for new entrants. This means that a nominal WACC should be applied to account for an assumed level of inflation.

6.1.5 Project and investor type assumptions

The different parameters of the WACC, as described throughout this section, have been defined based on a wide range of market evidence and regulatory precedent. We do however need to stress that some regulated assets, and the corresponding WACC determinations, are not directly comparable to the cost of capital for a merchant generating unit. There is much more limited precedent of regulators setting a cost of capital for a generating unit, when compared to WACC determinations of infrastructure projects or other natural monopolies. As a result, we do, at times, diverge from other regulatory decisions.

We have made the following assumptions regarding the nature of the project, the profile of the hypothetical investor, and the financing structure:

- the project is a green-field investment with no existing assets and associated financing costs;
- the economic life of the project is assumed to be 20 years; and
- the debt tenor is assumed to be 10 years.

6.2 Market-wide input parameters

6.2.1 Risk-free rate

The risk free rate reflects the return an investor would expect from a relatively 'safe' investment, such as government securities. We use the risk-free rate as the basis for defining both the cost of debt and the cost of equity.

For the purposes of our analysis we derive the risk-free rate from observations of the yields of:

- UK issued securities for Northern Ireland; and
- Irish issued securities for Ireland.

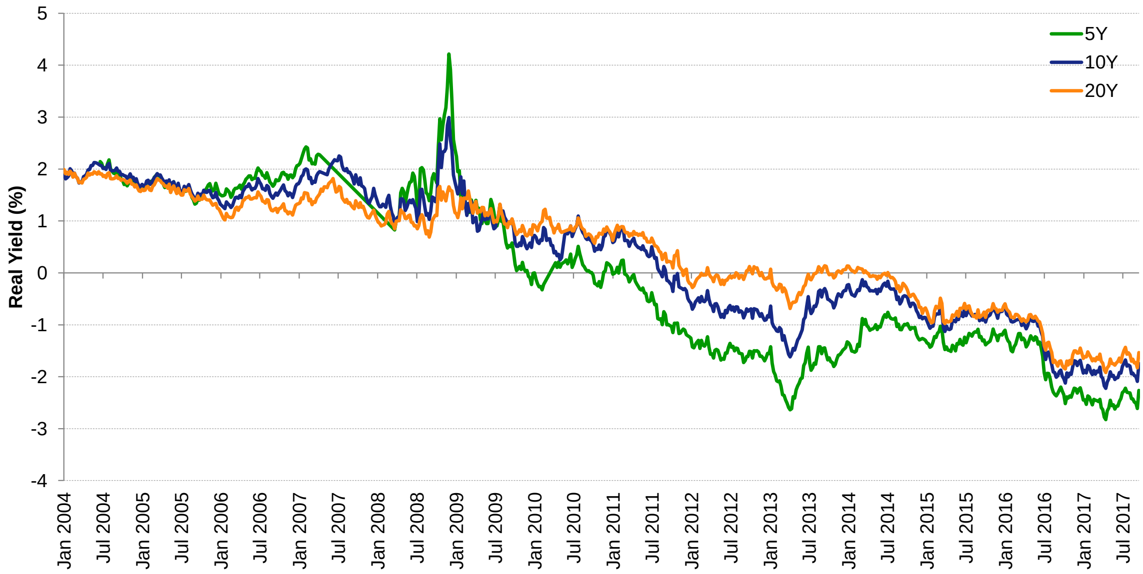
We analyse historical (and spot) values of UK Index Linked Gilts (ILGs) to inform our choice of the real risk-free rate for Northern Ireland. For Ireland, we use nominal yields of Irish Government Bonds adjusted for inflation[25].

6.2.1.1 Market evidence

UK ILGs are currently near historical lows. Quantitative Easing (QE) has put downward pressure on both interest rates and (real) bonds yields. The spot yield (as of 20 September 2017) of 10-year UK ILG is -1.76%. As shown in Figure 4, real yields of UK securities have been following a falling trend since early 2009. This is also supported by evidence from the UK nominal yield curve evolution, as show in Figure 5.

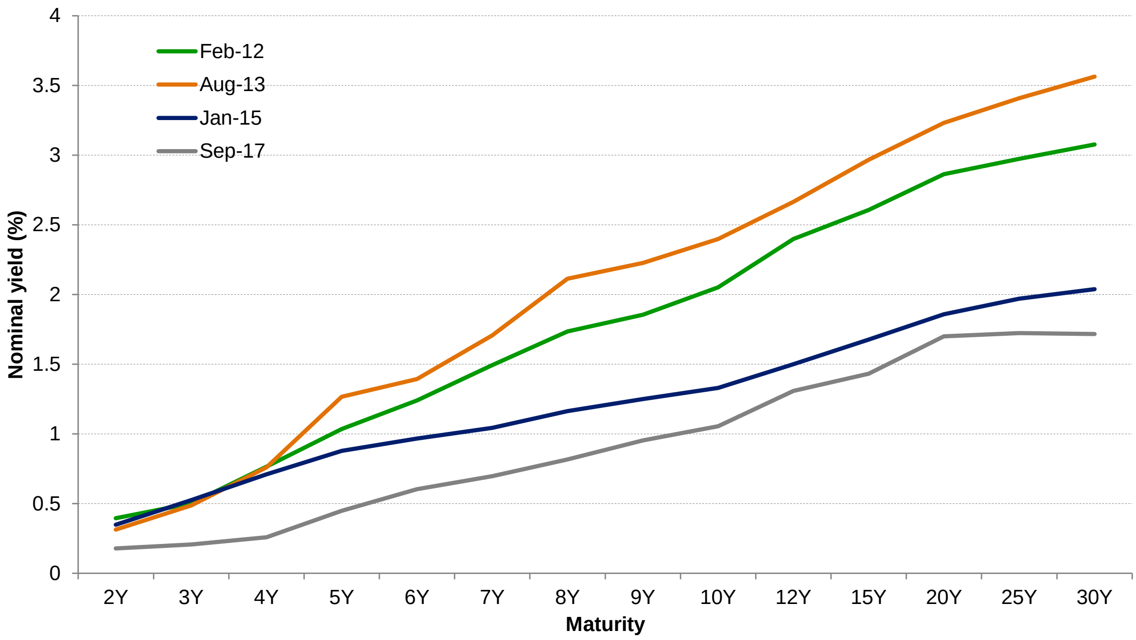
25 We do not assume a premium for Northern Ireland relative to the UK. This was explored by CEPA in the 2016 BNE analysis and by the CMA for the NIE T&D RP5 determination. A premium for Northern Ireland was not included in either case as the differences between NIE nominal yields and UK electricity distribution companies' bonds have decreased in recent years.

Figure 4 – UK Index Linked Gilts (as of September 2017)



Source: Bloomberg, Pöyry analysis.

Figure 5 – UK nominal yield curve



Source: Bloomberg, Pöyry analysis.

Bond yields in Ireland rose in 2009 and remained at relatively high levels, peaking in 2011, as shown in Figure 6. This was a result of the economic crisis in Ireland, fuelled by the banking (and housing) bubble, and reflects the perceived risk in investing in the Irish economy at the time. However, since 2013, Irish bond yields have also been following a falling trend, but are not as low as UK yields.

Figure 6 – Irish bonds 10 year benchmark*

*Unadjusted for inflation
Source: Thomson Reuters, Poyry analysis.

We have explored historical averages of the real UK and Irish 10-year bond yields over different periods of time. For the UK this results in a low average rate of approximately -1.5% based on the most recent two years based on 10 year gilts. A longer-term analysis, over 10 years of 10 year gilts results in a rate close to zero.

For Ireland we have assessed Irish Government Bonds adjusted for inflation expectations. Based on 10 year bonds, a one to two year average approximate risk-free rate range of 0.8-0.9% applies, whereas an average of the past 10 years results in a risk-free rate of approximately 3.7%, demonstrating the discrepancy between the current rate and long term averages.

Table 41 – Real yields from government bonds/gilts (%)

	2 year average	10 year average
UK ILG 10-year	-1.5	0.0
Irish government bond (adjusted for inflation)	0.9	3.7

Source: Bloomberg, Thomson Reuters, Pöyry analysis.

6.2.1.2 Regulatory precedent

In the recent past, regulators have tended to take a more conservative view when it comes to the risk-free rate, and in the UK, in particular, have not used a risk-free rate of less than 0.5%.

In June 2017 Gas Networks Ireland (GNI) and FTI proposed a risk free rate of 1.9% for GNI between 2017 and 2022[26].

The CMA reported a risk-free rate range from 1.0%-1.5% in their assessment of the period from 2007-2014. Other regulators have suggested values as shown in Table 42. Regulatory determinations have generally been based on 10-year trailing averages of 10-year ILGs, and with yields following a downwards trend the risk-free rate determined have also fallen. Remaining consistent with this approach would mean opting for a lower risk-free estimate than in previous years.

Table 42 – Selected regulatory decisions on risk-free rate

Regulator	Project	Risk-free rate (%)	Average (%)
Northern Ireland			
CAA	Q6 – Heathrow (2014-2019), Q6 – Gatwick (2014-2019), NERL	0.50-0.75	0.625
CC	NI Electricity RP5	1.50	1.50
CER/UR	Best New Entrant – NI 2015 Consultation	0.50-1.50	1.00
CER/UR	Best New Entrant – NI 2016 Decision	1.25	1.25
CMA	NIE T&D (2012-2017), Bristol Water	1.25-1.30	1.275
Ofcom	Fixed Access – Openreach, Fixed Access – BT Group, Fixed Access – Rest of BT, MCT	1.00-1.30	1.15

26 FTI Consulting – The Cost of Capital for GNI for the period October 2017 to September 2022 – A report to the Commission for Energy Regulation.

Regulator	Project	Risk-free rate (%)	Average (%)
Ofgem	RIIO ED1 (2015-2023), RIIO GD1 (2013-2021), RIIO T1 – Scottish TOs (2013-2021), RIIO T1 – NGET (2013-2021), RIIO T1 – NGGT (2013-2021)	1.00-2.00	1.50
Ofwat	PR14 (2015-2020)	1.25	1.25
ORR	PR13 (2014-2019), CP5	1.75	1.75
UR	PCI5	1.50	1.50
UR	GDI7 Decision (Sept 16)	1.25	1.25
UR	NIE RP6 PC Decision 2017-2024	1.25	1.25
UR	SONI PC Decision 2015-2020	1.25	1.25
Ireland			
CER	PR3 Mid-term review (2014-2015), PR3 for ESB and EirGrid (2011-2015), PC3 for BGN (2012-2017)	2.60-4.50	3.6
CER	Decision of TSO and TAO Transmission Revenue 2016-2020	1.90	1.90
CER/UR	Best New Entrant - RoI 2015 Consultation	1.00-2.50	1.75
CER/UR	Best New Entrant – RoI 2016 Decision	2.00	2.00
ComReg	Mobile and fixed line communications (Dec 2014)	2.10	2.10
CAR	DAA Charges (2015-2019)	1.50	1.50

Source: UKRN.

6.2.1.3 Recommendation

We propose a risk-free rate in the range of **1.25%-2.00% for Northern Ireland**. The lower bound is the risk-free range that was used in recent UR determinations. It is a forward-looking value and recognises that there is room for an increase in the current implied risk-free rate. The upper bound is more in line with the real yield on UK bonds observed prior to the 2008/09 economic crisis (and the QE periods that followed). For our WACC calculation for Northern Ireland we have chosen to use the lower bound value of **1.25%**.

For Ireland, we propose a risk-free rate in the range of **1.5%-2.5%**. The lower bound recognises that we would expect a small premium for Ireland when compared to the UK, whereas the upper bound is reflective of the real yields of Irish bonds observed before the 2008/2009 economic crisis. This range also reflects recent regulatory determinations. For our WACC calculation for Ireland we have chosen to use the lower bound value of **1.5%**.

6.2.2 Equity risk premium

The Equity Risk Premium ('ERP') is the difference between the expected return on a well-diversified portfolio and the risk-free rate. We have referenced two widely used sources that provide for values of the equity risk premiums in different countries/markets. These are the Credit Suisse Global Investment Returns Yearbook and analysis by Aswath Damodaran.

6.2.2.1 Market evidence

The Credit Suisse Global Investment Returns Yearbook reports on equity returns since 1900. Short-term and long-term annualised real returns on equity investments are shown in Table 43.

Table 43 – Annualised real returns on major asset classes for equity (%)

	Short-term			Long-term		
	2000-2014	**2000-2015**	**2000-2016**	**1900-2014**	**1900-2015**	**1900-2016**
Ireland	0.5	2.3	2.0	4.2	4.4	4.4
United Kingdom	1.0	1.7	2.4	5.3	5.4	5.5

Source: Credit Suisse Global Investment Returns Yearbook 2017, 2016, 2015.

The most recent figures for UK and Ireland equity risk premiums estimated by Aswath Damodaran are shown in Table 44.

Table 44 – Equity Risk Premiums (%)

	Equity Risk Premium
Ireland	5.57
United Kingdom	5.34

Source: Aswath Damodaran – Country default spreads and risk premiums, July 2017.

6.2.2.2 Regulatory precedent

For the 2016 BNE determination, an ERP of 5.25% was used for Northern Ireland and 4.50% for the Republic of Ireland. This was deduced by subtracting the risk-free-rate from the total market return.

The CMA reported an equity risk premium range from 4.0%-5.0% in their assessment of energy companies in the period from 2007-2014. Other regulatory determinations of ERP range from 4.50% to 5.75% as summarised in Table 45.

In June 2017 GNI and FTI proposed an ERP of 4.75% for GNI between 2017 and 2022[27].

[27] FTI Consulting – The Cost of Capital for GNI for the period October 2017 to September 2022 – A report to the Commission for Energy Regulation.

Table 45 – Regulatory precedent on Equity Risk Premium

Regulator	Project	ERP
United Kingdom		**%**
CAA	Q6 – Heathrow (2014-2019), Q6 – Gatwick (2014-2019), NERL	5.50-5.75
CC	NI Electricity NERL	5.00
CER/UR	Best New Entrant – NI 2015 Consultation	5.00
CER/UR	Best New Entrant – NI 2016 Decision	5.25
CMA	NIE T&D (2012-2017), Bristol Water	5.00-5.30
Ofcom	Fixed Access, MCT	4.80-5.10
Ofgem	RIIO ED1 (2015-2023), RIIO GD1 (2013-2021), RIIO T1 – Scottish TOs (2013-2021), RIIO T1 – NGET (2013-2021), RIIO T1 – NGGT (2013-2021)	5.00-5.25
Ofwat	PR14 (2015-2020)	5.50
ORR	PR13 (2014-2019), CP5	5.00
UR	PCI5	5.00
UR	GDI7 Decision (Sept 16)	5.25
UR	NIE RP6 PC Decision 2017-2024	5.25
UR	SONI PC Decision 2015-2020	5.25
Republic of Ireland		**%**
CER	PR3 Mid-term review (2014-2015), PR3 for ESB and EirGrid (2011-2015), PC3 for BGN (2012-2017)	4.75-5.20
CER	Decision of TSO and TAO Transmission Revenue 2016-2020	4.75
CER/UR	Best New Entrant - RoI 2015 Consultation	4.50
CER/UR	Best New Entrant – RoI 2016 Decision	4.50
ComReg	Mobile and fixed line communications (Dec 2014)	5.00
CAR	DAA Charges (2015-2019)	5.00

Source: CMA, UKRN.

6.2.2.3 Recommendation

We propose to use ERP values which are in line with recent regulatory decisions. Benchmarking against market evidence gives confidence that these are in the correct range. Therefore we recommend an ERP of **4.75% for Ireland** and **5.25% for Northern Ireland**.

6.2.3 Corporate taxation

We have opted for including taxation implicitly as part of the WACC (i.e. a pre-tax WACC), rather than treating it as a separate cost item. We have used the statutory corporation tax rates of 12.5% in Ireland[28] and 17% in Northern Ireland[29,30]. It was announced in March 2016 that corporation tax of 17% will apply in the UK from the financial year beginning 1 April 2020.

The Corporation Tax (Northern Ireland) Act 2015 devolves corporation tax rate setting powers to the NI Assembly[31]. However the suggested future rate of tax of 12.5% in Northern Ireland applies to small and medium sized companies only. In the absence of an official commitment on the implementation of a reduced corporation rate for non-SME businesses in Northern Ireland, we have used the UK 2020 rate.

6.3 Sector and project specific input parameters

6.3.1 Gearing

Gearing refers to the proportion of debt to total asset value. Different firms will have different capital structures (i.e. different proportion of debt and equity). For the purposes of the WACC determination for the net CONE, the gearing will impact:

- the weighting given on the cost of debt and the cost of equity;
- the equity beta; and
- indirectly on the debt margin.

6.3.1.1 Market evidence

The CMA published a working paper on the cost of capital as part of its GB energy market investigation. This includes an analysis of gearing levels for large UK energy companies. When it comes to generation companies, the analysis suggests a wide range for the relative gearing. Retail suppliers have significantly lower levels of debt relative to equity, whereas vertically integrated companies have gearing levels in the range 30%-40%. The values shown are averages across the period 2006-13 (see Figure 7). It is evident that gearing values for a number of listed companies are typically below regulatory assumptions.

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28 IDA Ireland – Ireland's Tax Regime.

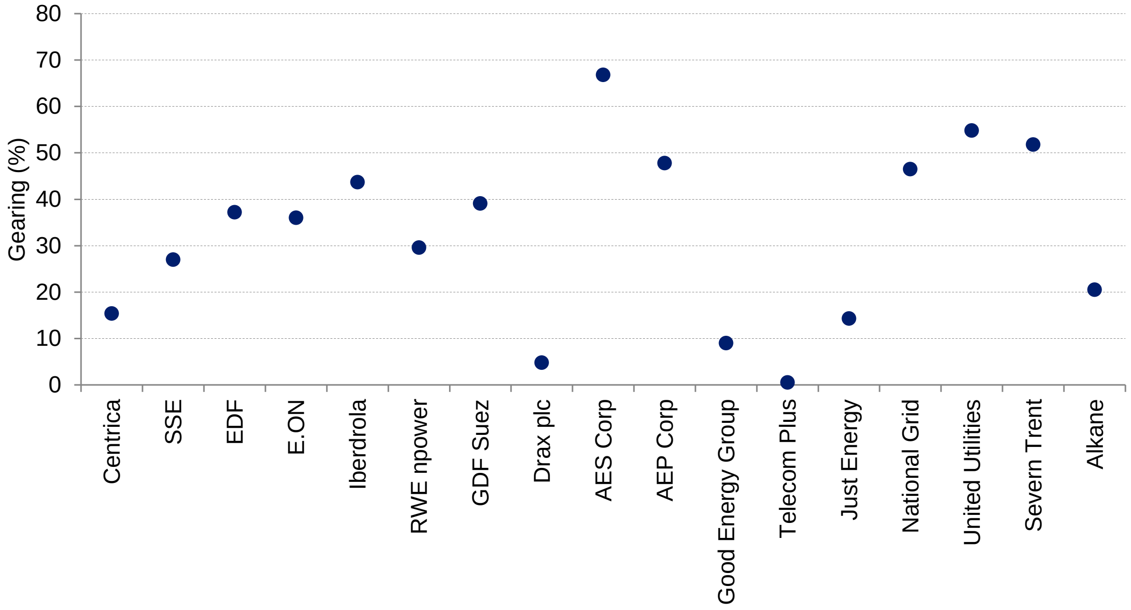
29 NI Assembly Corporation Tax (Northern Ireland) Bill.

30 Corporation Tax to 17% in 2020 – HMRC policy paper, 16 March 2016.

31 Corporation Tax (Northern Ireland) Act 2015.

When it comes to Ireland, limited relevant market evidence is available. ESB's reported gearing was 51% in 2016[32].

Figure 7 – Gearing examples in the UK energy market



Source: CMA, CEPA.

6.3.1.2 Regulatory precedent

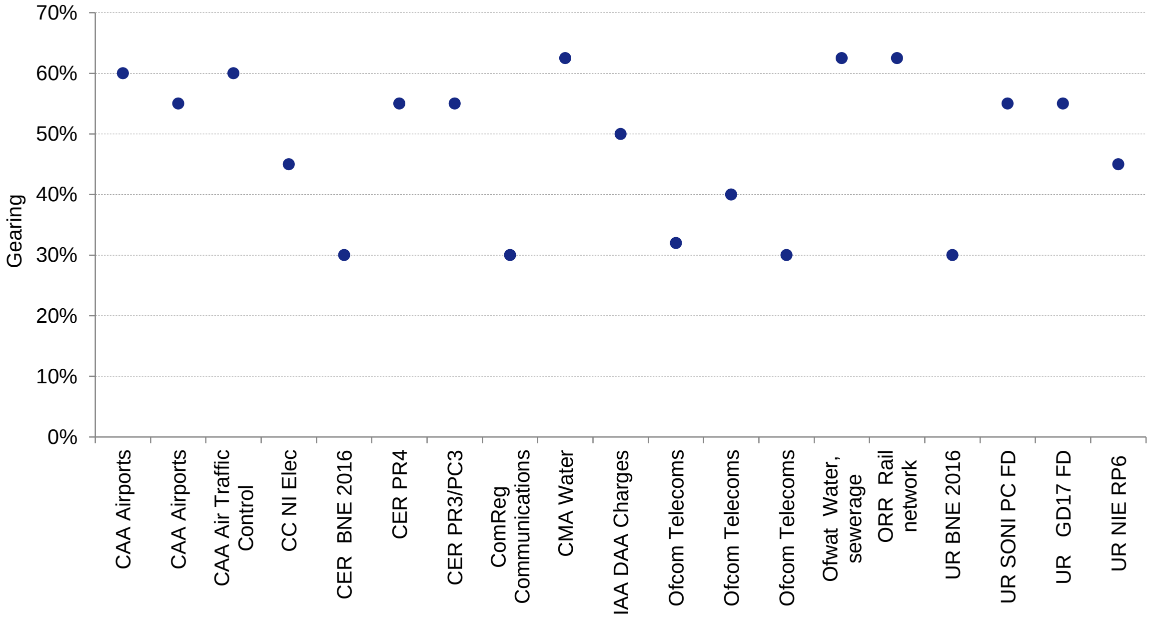
We have reviewed a wide range of gearing decisions made by various regulators. Ofgem has previously set gearing levels to be between 55% and 65% and the CER/UR between 30% and 60%. In the 2016 CER/UR BNE determination the assumed gearing level was 30%. This was reduced from 60% suggested in the initial BNE consultation in 2015.

In May 2017 the UK Regulators Network (UKRN) published its annual update report on the cost of capital[33]. It published gearing levels resulting from regulatory decisions made in the previous 4 years. As shown in Figure 8 the gearing for regulated assets was often determined to be between 50% and 65%.

32 ESB Debt Investor Presentation 2016 Results and Business Update.

33 http://www.ukrn.org.uk/wp-content/uploads/2017/05/20170503-UKRN-Annual-WACC-Comparison-Report_FINAL.pdf

Figure 8 – Regulatory gearing determinations



Source: CMA, UKRN, UR/CRU.

6.3.1.3 Recommendation

We do recognise that the assumption of 60% gearing has remained unchanged for a long period of time, prior to the 2016 BNE determination, under the SEM arrangements, and is the level used for the capacity markets in PJM and ISO-NE. Other (higher) regulatory figures for gearing are largely for regulated network businesses and so their capital structures reflect the nature of their business. However, market evidence consistently points towards lower levels of gearing for competitive segments. We, therefore, recommend using a **40% gearing** (i.e. 40% debt of the total asset value).

6.3.2 Asset beta and equity beta

The equity beta of an investment is a measure of correlation of the risk of the investment compared to the market as a whole. The equity beta can be inferred from capital market data. For the purpose of the net CONE determination, we are assuming a ‘generic’ company (and a ‘generic’ project). This means we would need to first define an (unlevered) asset beta by de-levering equity betas based on market data, and then re-lever based on our assumed gearing to arrive at the equity beta. We have assumed that the debt beta is very small in comparison to the equity beta and approximated it to zero. This is a common simplification in the calculation of equity beta from asset beta and vice versa.

6.3.2.1 Market evidence

We have collected unadjusted equity betas using 5-year monthly averages for selected energy companies, as show in Table 46.

Table 46 – 5-year monthly equity betas from energy companies as of September 2017

Company	5 year monthly beta
Alkane Energy	0.37
Centrica plc	0.93
Drax Group	1.09
E.On	1.26
ESB	0.84
National Grid PLC	0.74
RWE AG	0.76
Severn Trent	1.10
SSE plc	0.58
United Utilities	1.02

Source: Thomson Reuters.

Aswath Damodaran has also published estimated asset betas for different market sectors in Europe, and suggests an asset beta of 0.63 for the European power sector. Assuming 40% gearing this translates into an equity beta of 1.00 for Ireland and 0.98 for Northern Ireland, when accounting for differences in tax rates.

At the same time, analysis of companies operating in PJM, suggest an equity beta in the range of 0.49-1.29[34].

6.3.2.2 Regulatory precedent

The CMA reported a range of asset betas from 0.5 to 0.6 for vertically integrated and generation companies and 0.7-0.8 for retail supply companies in their assessment of the period 2007-2014. A summary of asset and equity betas from a range of regulatory decisions are shown below, suggesting that the equity beta range should be between 0.7 and 1.2.

34 The Brattle Group – Cost of New Entry Estimated for Combustion Turbine and Combined Cycle Plants in PJM.

Table 47 – Regulatory determinations for asset and equity betas

Regulator	Project	Asset beta	Equity beta
United Kingdom			
CER/UR	Best New Entrant - NI (2016)	0.56	0.76
CC	NI Electricity NERL	0.40	0.70
CMA	NIE T&D (2012-2017)*, Bristol Water	0.32	0.75- 0.85
CAA	Q6 – Heathrow (2014-2019), Q6 – Gatwick (2014-2019), NERL	0.50-0.56	1.10-1.13
Ofcom	Fixed Access*, MCT	0.50	0.69-1.17
Ofgem	RIIO ED1 (2015-2023)*, RIIO GD1 (2013-2021)*, RIIO T1 – Scottish TOs (2013-2021)*, RIIO T1 – NGET (2013-2021)*, RIIO T1 – NGGT (2013-2021)*		0.90-0.95
Ofwat	PR14 (2015-2020)	0.30	0.80
ORR	PR13 (2014-2019)*, CP5	0.37	0.95
UR	PCI5	0.44	0.83
UR	GDI7 Decision (Sept 16)	0.40	0.77
UR	NIE RP6 PC Decision 2017-2024	0.38	0.61
UR	SONI PC Decision 2015-2020	0.60	1.21
Republic of Ireland			
CER	PR3 Mid-term review (2014-2015)*, PR3 for ESB and EirGrid (2011-2015)*, PC3 for BGN (2012-2017)*		0.67-0.78
CER/UR	Best New Entrant – RoI (2016)	0.56	0.76
CER	PR4 (2016-2020) Decision of TSO and TAO Transmission Revenue 2016-2020	0.40	0.89
GNI[1]	PC4 (2017-2022)	0.42-0.44	0.93-0.98

Regulator Project	Asset beta	Equity beta	Regulator Project
ComReg	Mobile and fixed line communications (Dec 2014)*		0.93
CAR	DAA Charges (2015-2019)*		1.20

*Asset beta not reported.
[1] Report to the CER, completed by FTI Consulting
Source: UKRN, CEPA.

6.3.2.3 Recommendation

We propose an equity beta in the range **0.76-1.00** for Ireland and **0.76-0.98** for Northern Ireland. The lower bound is reflective of the regulatory precedent, whereas the upper bound is based Aswath Damodaran's analysis. We propose to use the mid-points of these ranges in our calculation of the BNE WACC.

6.3.3 Debt premium (and all-in cost of debt)

The debt premium is the mark-up that debt providers would include above the risk-free rate. It is added to the risk-free rate, defining the all-in cost of debt.

6.3.3.1 Market evidence

The nominal UK 10 year gilt treasury nominal yield to maturity was 1.38% and the Irish Government 10 year Bond yield was 0.76% when our analysis was completed. Table 48 presents the spread between bonds issues by some selected energy companies and the gilt yields.

Table 48 – Spread of selected energy companies to corresponding government bonds, September 2017

Company	Maturity	Credit rating	Nominal yield to maturity today (21/9/17)	Spread to gilt today (bps)
Centrica	Apr-27	BBB+	5.74	4.37
ESB	Jun-27	A-	1.24	0.49
National Grid Elec	Jun-27	A-	2.17	0.80
NIE Finance	Jun-26	BBB+	2.20	0.83
Northern gas networks	Jun-27	BBB+	2.22	0.85
Northern Powergrid	Apr-25	A	1.87	0.50
Southern GN	Feb-25	BBB +	2.00	0.63
Southern GN	Mar-29	BBB +	2.36	0.99
WPD	Dec-28	BBB +	4.76	3.39
WWU	Dec-23	A-	1.73	0.36
WWU	Apr-27	A-	5.74	4.37
WWU	Mar-28	A-	2.28	0.91

Source: Thomson Reuters, Pöyry analysis.

6.3.3.2 Regulatory precedent

The Competition and Markets Authority ('CMA') published the cost of capital of energy businesses operating in generation and retail supply elements of the value chain and businesses that are vertically integrated. This was published as part of the investigation into the energy market in GB[35]. The figures shown below correspond to what the CMA considers an investor could reasonably have expected for the cost of capital when making an investment decision between 2007 and 2014. The CMA's analysis should not be

[35] CMA Energy marker investigation, February 2015.

compared directly with current market evidence as UK corporation tax rates and other elements may be out of date.

Table 49 – Average cost of debt and debt premium estimates for the period 2007-2014

	Vertically Integrated		Generation		Retail Supply	
	Low	**High**	**Low**	**High**	**Low**	**High**
Nominal risk-free rate	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Debt premium	1.0%	2.0%	1.5%	3.0%	-	-
Cost of Debt (nominal)	5.0%	6.0%	5.5%	7.0%	-	-

Source: CMA.

The UKRN also published cost of debt for a range of regulatory decisions. Notably the UR set the cost of debt at 2.36% for GDI7-PNGL in September 2016.

Table 50 – Selected regulatory decisions on cost of debt

Regulator	Project	Pre-tax cost of debt (%)
NI		
CAA	Q6 – Heathrow (2014-2019), Q6 – Gatwick (2014-2019), NERL	2.45-3.20
CC	NI Electricity RP5	3.10
CER/UR	Best New Entrant - NI (2016)	2.10
CMA	NIE T&D (2012-2017), Bristol Water	2.60-3.40
Ofcom	LLU WLA, WBA, MCT, LLCC	2.10-2.80
Ofwat	PR14 (2015-2020)	2.59
ORR	CP5	3.00
UR	PCI5	1.20
UR	GDI7 Decision (Sept 16)	2.45
UR	NIE RP6 PC Decision 2017-2024	1.63
UR	SONI PC Decision 2015-2020	2.95
Ireland		
CER	PR3 Mid-term review (2014-2015), PR3 for ESB and EirGrid (2011-2015), PC3 for BGN (2012-2017)	3.75-4.50
CER	PR4 (2016-2020)	2.90
CER/UR	Best New Entrant - RoI (2016)	2.75
GNI	PC4 (2017-2022)	2.90
ComReg	Mobile and fixed line communications (Dec 2014)	3.55
CAR	DAA Charges (2015-2019)	3.00

Source: UKRN, CEPA, CER/UR.

6.3.3.3 Recommendation

In line with the risk-free rates we are recommending for Ireland and Northern Ireland, we suggest using a (real) cost of debt in the range of **2.50% - 4.00% for Ireland** and **2.25% - 3.00% for Northern Ireland**. The implied risk premium for Ireland is reflective of ESB's spread to the Irish government bond, and the implied risk premium for Northern Ireland is within the range of the observed market data. For the BNE WACC calculation we propose to use a cost of debt of 2.75% for Ireland and 2.5% for Northern Ireland. These figures reflect the longer-term view compared to today's low cost of debt, and are in line with recent regulatory decisions.

6.4 Proposed cost of capital

6.4.1 Cost of debt

The cost of debt has been estimated based on:

$CoD = r_f + D_p$

where

CoD = cost of debt;

r_f = risk-free rate;

D_p = debt premium.

6.4.2 Cost of equity

We use the Capital Asset Pricing Model ('CAPM') in order to estimate the cost of equity:

$CoE = r_f + \beta_{Equity} * ERP$

where

CoE = cost of equity;

r_f = risk-free rate;

ERP = equity risk premium for the market portfolio; and

β_{Equity} = equity beta, a measure of non-diversifiable risk of the security relative to the market portfolio.

6.4.3 Weighted Average Cost of Capital ('WACC')

Based on our assessment, as detailed above, the appropriate range for the real pre-tax WACC is 4.5% - 6.6% in Ireland and 4.7% - 6.6% in Northern Ireland. We use the Fisher formula to convert to a nominal WACC, given that the 10 year contracts will not be indexed to inflation. Based on an assumed 2% (long-term) annual inflation[36], the equivalent nominal pre-tax WACC is 6.6% - 8.7% in Ireland and 6.8% - 8.7% in Northern

36 Long term annual inflation assumption made by Pöyry

Ireland. Based on our analysis above we suggest using a real pre-tax WACC of 5.0% for Ireland and 5.2% for Northern Ireland. The equivalent nominal pre-tax WACC is 7.1% and 7.3% for Ireland and Northern Ireland respectively.

Table 51 – Proposed WACC

	Ireland			Northern Ireland		
	Low	**High**	**Selected**	**Low**	**High**	**Selected**
Cost of debt	2.50%	4.00%	2.75%	2.25%	3.50%	2.50%
Risk-free rate	1.50%	2.50%	1.50%	1.25%	2.00%	1.25%
Equity Risk Premium (ERP)		4.75%			5.25%	
Asset Beta		0.63			0.63	
Equity Beta	0.76	1.00	0.88	0.76	0.98	0.87
Post-tax Cost of Equity	5.1%	7.2%	5.7%	5.2%	7.1%	5.8%
Taxation		12.5%			17.0%	
Pre-tax Cost of Equity	5.8%	8.3%	6.5%	6.3%	8.6%	7.0%
Gearing		40%			40%	
Real pre-tax WACC	**4.50%**	**6.56%**	**4.99%**	**4.69%**	**6.56%**	**5.20%**
Equivalent Vanilla WACC	4.07%	5.94%	4.50%	4.04%	5.68%	4.49%
Nominal pre-tax WACC	**6.59%**	**8.69%**	**7.09%**	**6.78%**	**8.69%**	**7.31%**

Summary

	Ireland	**Northern Ireland**
Real pre-tax WACC(%)[1]	5.0%	5.2%
Nominal pre-tax WACC[1,2]	7.1%	7.3%
Nominal post-tax WACC[1,2]	6.5%	6.4%

[1] Based on parameter choices within ranges as discussed throughout report.
[2] Inflation rate of 2% assumed.

The nominal post-tax WACC of 6.5% for Ireland and 6.4% for Northern Ireland is somewhat lower than the nominal post-tax WACC in both ISO-NE and PJM (where a nominal, post-tax WACC is used), both of which were calculated to be 8%. Our calculated real cost of capital is also lower than what was assumed in the GB capacity market, where a 7.5% real hurdle rate was used for defining the gross CONE.

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7. NET COST OF NEW ENTRY

7.1 Gross and net CONE for reference peaking and CCGT plant

7.1.1 Gross CONE

On the basis of the gross CONE, a distillate OCGT sited in Northern Ireland appears to be the cheapest option for meeting the last MW of demand on the system (i.e. has the lowest gross CONE). The net output gain of the dual fuel option when compared to the distillate only option, appears to offset the somewhat higher overall capital costs (as can be seen from the comparison of the distillate only option and the dual option in Ireland). However, the higher annual fixed cost for the dual option (due to the absence of short term exit gas capacity charges in Northern Ireland) means that the distillate option is more cost competitive.

A CCGT has a significantly higher gross CONE when compared to an OCGT. The gross CONE (in real 2017 money terms) for the different reference technologies is presented in Table 52.

Table 52 – Gross CONE (€/kW – de-rated, real 2017 money)

Jurisdiction		**Ireland**			**Northern Ireland**	
Technology	OCGT distillate	OCGT dual	CCGT dual	OCGT distillate	OCGT dual	CCGT dual
Annualised capital cost	55.6	54.5	69.5	56.0	55.4	70.6
Annual fixed cost	33.6	32.8	73.7	27.8	40.3	65.2
Gross CONE	**89.2**	**87.3**	**143.3**	**83.8**	**95.7**	**135.8**

Table 53 shows the gross CONE in nominal money terms. To arrive at the gross CONE in nominal money terms, capital costs (presented in real 2017 money terms) **are inflated to the year before the first year of operation and a nominal WACC is applied**. Annual fixed costs are assumed to continue to rise in line with inflation over the entire economic lifetime, and the annual fixed cost value presented in Table 53 is an annuity (ie. the average annual value that is equivalent to the variable annual cashflow).

Table 53 – Gross CONE (€/kW – de-rated, nominal money)

Jurisdiction	**Ireland**			**Northern Ireland**		
Technology	OCGT Distillate	OCGT dual	CCGT dual	OCGT distillate	OCGT dual	CCGT dual
Annualised capital costs	71.9	70.6	90.0	72.5	71.7	91.3
Annual fixed costs	43.5	42.4	95.5	35.9	52.1	84.3
Gross CONE	**115.5**	**113.0**	**185.5**	**108.4**	**123.8**	**175.7**

7.1.2 Net CONE

However, when the expected inframarginal rent and DS3 income are taken into account, a CCGT located in Northern Ireland is in a position to meet the marginal MW of demand more cost effectively. When it comes to Ireland, the net CONE of a CCGT is close to that of the two OCGTs, but is still marginally above the net CONE of a distillate OCGT.

The substantially lower annual fixed costs for a CCGT in Northern Ireland result in a difference of around 8 €/kW – de-rated (in real 2017 money) when compared to Ireland. Business rates are assumed to be lower in Northern Ireland and the current gas capacity entry and exit fees in the two countries suggest lower gas transportation costs in Northern Ireland.

Table 54 presents the gross and net CONE estimates for the different reference technologies in Ireland and Northern Ireland, alongside the breakdown in the different cost and net revenue building blocks. For the inframarginal rent and the DS3 income, we present an annualised value over the entire period of operation as DS3 income and inframarginal rent do not remain constant in real money terms over time.

Table 54 – Gross and net CONE (€/kW – de-rated, real 2017 money)

Jurisdiction	**Ireland**			**Northern Ireland**		
Technology	OCGT Distillate	OCGT Dual	CCGT dual	OCGT distillate	OCGT dual	CCGT dual
Gross CONE	**89.2**	**87.3**	**143.3**	**83.8**	**95.7**	**135.8**
Inframarginal rent	-3.1	-3.1	-62.4	-3.1	-3.1	-62.5
DS3 income	-12.4	-12.4	-6.8	-12.4	-12.4	-6.8
Net CONE	**73.7**	**71.8**	**74.0**	**68.3**	**80.2**	**66.5**

It is clear that the expectation of inframarginal rent captured by a reference new entry CCGT has a strong impact on its net CONE. The estimated net CONEs for OCGT and the CCGT are fairly close in both jurisdictions. Even small changes in market fundamental assumptions that would impact the inframarginal rent captured by a CCGT would then also influenc e the OCGT/CCGT balance.

Table 55 presents the gross and net CONE calculations in real 2022 money terms. The higher values for all cost components are a result of the assumed inflation.

Table 55 – Gross and net CONE (€/kW – de-rated, real 2022 money)

Jurisdiction		**Ireland**			**Northern Ireland**	
Technology	OCGT Distillate	OCGT dual	CCGT dual	OCGT distillate	OCGT dual	CCGT dual
Gross CONE	**97.4**	**95.3**	**156.5**	**91.6**	**104.6**	**148.3**
Inframarginal rent	-3.3	-3.3	-68.2	-3.3	-3.3	-68.3
DS3 income	-13.6	-13.6	-7.4	-13.6	-13.6	-7.4
Net CONE	**80.5**	**78.4**	**80.9**	**74.6**	**87.6**	**72.6**

With the net CONE envisaged to be in nominal money terms, we need to include inflation expectations in the discounted cashflow analysis. Ultimately, we need to take two steps from our estimated gross and net CONE in 2017 money terms to arrive to the level of money that would be required on an annual basis to deliver a Net Present Value of zero over the 20 year economic lifetime of a project:

- adjust the gross and net CONE from 2017 money to 2022 money (equivalent to 5 years of inflation); and
- estimate the gross and net CONE in nominal terms (and with the use of a nominal WACC for annuitising capital costs) to account for inflation over the entire economic lifetime of the project (equivalent to 20 years of inflation).

The two approaches that can be used ('level-nominal' vs. 'level-real adjusted for inflation') are mathematically equal in an ex-ante determination (ie. yield the same Net Present Value). The choice between the two approaches depends on the policy decision as to who should bear inflation risk. With the 'nominal' approach the capacity provider bears the inflation risk, whereas with the 'real' approach (and assuming inflation indexation in the future) that risk is removed from the capacity provider.

We have used a long term average 2% inflation for Ireland and Northern Ireland post 2020. Table 56 shows the equivalent net CONE values in nominal money terms.

Table 56 – Gross and net CONE (€/kW – de-rated, nominal)

Jurisdiction	Ireland			Northern Ireland		
Technology	OCGT Distillate	OCGT dual	CCGT dual	OCGT distillate	OCGT dual	CCGT Dual
Gross CONE	**115.5**	**113.0**	**185.5**	**108.4**	**123.8**	**175.7**
Inframarginal rent	-4.0	-4.0	-80.8	-4.0	-4.0	-80.8
DS3 income	-16.1	-16.1	-8.8	-16.1	-16.1	-8.8
Net CONE	**95.4**	**93.0**	**95.9**	**88.4**	**103.8**	**86.0**

The lack of indexation for long-term contracted capacity necessitates the use of this 'level-nominal' approach. Otherwise new entrants would likely not be in a position to recover their costs under normal inflationary conditions. Conversely, the use of this approach may mean that the net CONE value is overstated in the short-term (putting an upwards bias on the demand curve) with existing capacity capturing payments above the efficient new entry level.

7.1.3 Conclusions

The analysis presented in this report suggests that a CCGT sited in Northern Ireland has the lowest net CONE. The geographic choice is driven by the lower annual fixed costs for a CCGT in Northern Ireland, reflecting lower business rates and estimated gas transportation costs.

The lower net CONE for a CCGT relative to an OCGT in Northern Ireland is primarily driven by the relative size of the expected inframarginal rent. This arises because the approach to projecting inframarginal rent for the different technology choices reflects the very different expectations of their mode of operation – baseload/mid-merit versus peaking. As the CCGT is anticipated to operate at much higher load factors than an OCGT, and due to its significantly higher relative efficiency, the scope for accruing inframarginal rent is higher. In Ireland, on the other hand, the inframarginal rent captured by a CCGT is not enough to offset the difference in capital expenditure and annual fixed costs (gas charges in Ireland are higher when compared to Northern Ireland).

However, a CCGT has greater (spot) market exposure than an OCGT. The majority of OCGT margins will come from a 10-year capacity contract which should reduce the risk for investors and may, potentially, attract a lower WACC. In our analysis we have not assumed a difference in the WACC between a CCGT and an OCGT to reflect this (potentially) different market risk exposure. We have however taken a conservative view on the expected inframarginal rent for a reference CCGT.

Table 54 to Table 56 highlight the importance of applying the correct money base to the agreed net CONE value. While it does not change the technology decision, the fact that the net CONE value for a Northern Ireland CCGT can range from 66.5 €/kW (in real 2017 money) to 86.0 €/kW (in nominal terms) highlights the importance of ensuring the net CONE value applied is consistent with the wider capacity contract terms.

ANNEX A – GAS TURBINE LONG-LIST

Table 57 – Gas turbine long-list

Manufacturer & Model	Commercially available	Proven track record	Start time <20 min.	Dual fuel	Selected
Ansaldo AE64.3A	Yes	Yes	Yes	Yes	Yes
Ansaldo AE94.2	Yes	Yes	Yes	Yes	Yes
GE 6B.03	Yes	Yes	Yes	Yes	Yes
GE 6F.01	Yes	Yes	Yes	Yes	Yes
GE 6F.03	Yes	Yes	No	No	No
GE GT13E2	Yes	Yes	Yes	Yes	Yes
GE 9E.03	Yes	Yes	Yes	Yes	Yes
GE 9E.04	Yes	Yes	Yes	Yes	Yes
GE LM6000 PC SPRINT	Yes	Yes	Yes	Yes	Yes
GE LM6000 PD SPRINT	Yes	Yes	Yes	Yes	Yes
GE LM6000 PF SPRINT-25	Yes	Yes	Yes	Yes	Yes
GE LMS100PA	Yes	Yes	Yes	Yes	Yes
Kawasaki GPB300D	Yes	Yes	N/A	No	No
MHPS H-25(42)	Yes	Yes	Yes	Yes	Yes
MHPS H-100(110)	Yes	Yes	Yes	Yes	Yes
Saturn GTE-110	Yes	Yes	Yes	Yes	Yes
P+W FT8 Swift Pac 30	Yes	Yes	Yes	Yes	Yes
P+W FT8 Swift Pac 60	Yes	Yes	Yes	Yes	Yes
Siemens Industrial RB211 GT61	Yes	Yes	Yes	Yes	Yes
Siemens SGT-600	Yes	Yes	Yes	Yes	Yes
Siemens SGT-700-33	Yes	Yes	Yes	Yes	Yes
Siemens SGT-750	Yes	Yes	Yes	Yes	Yes
Siemens SGT-800-50	Yes	Yes	Yes	Yes	Yes
Siemens Industrial TRENT 60 DLE	Yes	Yes	Yes	No	No
Siemens SGT5-2000E (25MAC)	Yes	Yes	Yes	Yes	Yes

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ANNEX B – COSTS FOR NORTHERN IRELAND IN LOCAL CURRENCY

Table 58 – Capital cost estimates (£ million)

Jurisdiction		**Northern Ireland**	
Technology	*OCGT distillate*	*OCGT dual*	*CCGT*
EPC costs	80.1	80.4	231.3
Site procurement cost	0.8	0.8	3.2
Electrical connection costs	5.0	5.0	5.0
Water connection costs	0.4	0.4	0.6
Gas connection costs	0.0	3.2	4.0
Owners contingency	4.0	4.0	11.6
Financing costs	1.6	1.6	4.6
Interest during construction	1.0	1.1	4.5
Construction insurance	0.7	0.7	2.1
Initial fill of fuel oil tanks	2.1	1.8	5.0
Project development	4.8	4.8	13.9
Commissioning utilities costs	2.0	2.0	5.8
Operating spares	1.2	1.2	3.5
Accession fees	0.0	0.0	0.0
Participation fees	0.0	0.0	0.0
Total	**103.8**	**107.2**	**295.0**

Note: Costs converted from Euro to GBP Sterling using average exchange rate for 2017 (Jan – Oct 2017).

Table 59 – Annual fixed cost estimates (£ million)

Technology	Northern Ireland OCGT distillate	Northern Ireland OCGT dual	Northern Ireland CCGT
Trading and admin	0.6	0.6	1.9
Personnel	0.7	0.7	2.8
Insurance	0.5	0.5	1.4
Fixed maintenance	0.4	0.4	1.2
Fixed fee under LTSA	0.5	0.5	1.5
Business rates	0.5	0.6	2.0
Market operator rates	0.0	0.0	0.0
Electricity transportation charges	0.9	1.0	2.2
Gas transportation charges	0.0	2.1	9.4
Total	**4.2**	**6.4**	**22.2**

Note: Costs converted from Euro to GBP Sterling using average exchange rate for 2017 (Jan – Oct 2017).

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