COSTS OF A BEST NEW ENTRANT PEAKING PLANT FOR THE CALENDAR YEAR 2016

REPORT FOR THE REGULATORY AUTHORITIES

May 2015

Initial report

FOR PUBLICATION

Submitted by:

Cambridge Economic Policy Associates Ltd in association with Ramboll

Contents

IMPORTANT NOTICE

This report has been commissioned by the Northern Ireland Authority for Utility Regulation (NIAUR) and the Commission for Energy Regulation (CER). However, the views expressed are those of CEPA alone. CEPA accepts no liability for use of this report or any information contained therein by any third party.

1. INTRODUCTION AND CONTEXT

1.1. Overview

Cambridge Economic Policy Associates (CEPA), working with Ramboll, is pleased to submit this initial report on the costs of a Best New Entrant (BNE) peaking plant for the calendar year 2016 to the Northern Ireland Authority for Utility Regulation (NIAUR) and the Commission for Energy Regulation (CER), collectively the Regulatory Authorities (RAs).

1.2. Purpose of the initial report

This independent report provides CEPA and Ramboll's estimate of the fixed costs that a rational investor would incur in constructing and operating a peaking plant to enter the Single Electricity Market (SEM) in 2016. The purpose of the report is to inform the RA's determination of the size of the capacity payment pot for the SEM trading year 2016.

This report sets out the approach which CEPA and Ramboll have taken to determining costs and outlines all assumptions made. To the fullest extent possible, CEPA and Ramboll have sought to consistently apply the methodology used to determine the fixed costs of a peaking plant for previous BNE trading years.

This report is intended to inform the RA's consultation on the BNE price for 2016. CEPA and Ramboll would welcome views from market participants on the issues raised. In particular, we would welcome evidence to support comments about the validity of costs or current market conditions.

1.3. Company profiles

This report has been developed jointly by CEPA and Ramboll.

CEPA is a London based economic and finance advisory firm with a leading economic regulation and power sector practice. CEPA's staff and associates have extensive experience in power generation investment appraisal, assessment of the cost of capital and analysis of elements of the fixed costs (e.g. network charges) that would be incurred by the BNE peaking plant.

Ramboll is a major international engineering consultancy founded in Denmark in 1945. Today, the Ramboll Group employs close to 10,000 experts and has a significant presence in the UK, northern & Eastern Europe including Ukraine, India and the Middle East. With more than 200 offices in 22 countries, Ramboll prides itself on its ability to deliver global knowledge, locally. Ramboll has designed, constructed and provided operational support to more than 90 major power plants with comprehensive international experience, is fully abreast of all the latest technical developments and has unique hands-on experience from plant operation.

1.4. The capacity payment mechanism

1.4.1. Objectives of the capacity payment mechanism

The capacity payment is an important part of the SEM. The RAs introduced a Capacity Payment Mechanism (CPM) in order to fulfil the objectives outlined in Box 1.1.

Box 1.1: Objectives of the Capacity Payment Mechanism

- **Capacity Adequacy/ Reliability of the system -** The CPM must encourage both the construction and maintained availability of capacity in the SEM. Security of the system, will be the core feature of the CPM.
- **Price Stability -** The CPM should reduce market uncertainty compared to an energy only market, taking some of the volatility out of the energy market.
- **Simplicity -** The CPM should be transparent, predictable and simple to administer, in order to lower the risk premium required by investors in generation. A complex mechanism could reduce investor confidence in the market and increase implementation costs.
- **Efficient price signals for Long Term Investments -** In theory it would be possible to incentivise vast amounts of capacity over and above that necessary for system security in the SEM, although the cost of implementing such a scheme may be unacceptable to customers. The CPM should meet the criterion in this section at the lowest reasonable cost. Revenues earned by generators should still efficiently signal appropriate market entry and exit.
- **Susceptibility to Gaming -** The CPM should not be susceptible to gaming and, ideally, should not rely unduly on non-compliance penalties.
- **Fairness -** The CPM should not unfairly discriminate between participants. An appropriate CPM will maintain reasonable proportionality between the payments made to achieve capacity adequacy and the benefits received from attaining capacity adequacy.

Source: Regulatory Authorities / CEPA

The CPM is fixed on an annual basis, with shorter duration “capacity periods” reflecting that the same quantity of generation is not necessarily available at all times of the year.

The CPM requires two key features:

- a Capacity Requirement which was 7,049MW in 2014 and 7,046MW for 2015; and
- a price element which was €80.27/kW/year for 2014 and €81.60/kW/year for 2015.

The product of these price and quantity elements yielded an Annual Capacity Payment Sum (ACPS) for the 2014 and 2015 trading years of €565.9m and €576.01m respectively.

1.5. Structure of this document

The remainder of this document is structured as follows:

- Section 2 discusses the key concepts involved in estimating the costs of a BNE plant and outlines our methodology.
- Section 3 provides details of the approach used to determine the appropriate BNE technology option.
- In Section 4 we consider the costs associated with the chosen BNE technology option.
- Section 5 sets out financial considerations, including our estimate of the cost of capital required by an investor in a BNE plant.
- Section 6 provides details of the infra-marginal rent and ancillary service revenues the plant could be expected to earn through operation in the energy market.
- Section 7 sets out our initial estimate of the BNE price based on the assumptions set out in the remainder of the document.

The document also includes two annexes:

- Annex A shows the filtering process used to reduce the long list of technology options.
- Annex B provides a more detailed assessment of relevant financial issues.

2. Overview of approach

This section sets out the approach which CEPA and Ramboll have taken to determining the costs a BNE peaking plant. As this is the fifth time CEPA has been commissioned to determine the costs of a BNE peaking plant, we have employed a substantively similar approach as in previous trading years. We have sought to reflect lessons learned from previous calculations, as well as revisiting and refreshing our analysis in light of recent market developments.

2.1. BNE calculation

The BNE calculation is designed to determine the costs that a rational investor in a peaking plant which served the final megawatt (MW) of demand would incur at the point when the market is in equilibrium. It is therefore a theoretical exercise based around assumptions about the behaviour of a rational investor in a notional plant. However, in practice it is not sensible to consider BNE costs in a purely theoretical manner. Therefore, whilst one is dealing with a notional plant, it is necessary, to the extent practicable, to develop cost estimates with reference to market evidence.

2.1.1. Questions to consider in determining BNE costs

While the BNE calculation requires the estimation of a significant number of costs and revenue elements, at the highest-level it requires a series of relatively simple questions to be addressed. These questions relate to the characteristics of a rational investor in peaking plant capacity, the decisions that the investor would take and the costs they would incur in bringing a peaking plant to market in 2016.

The high-level questions and a number of the more detailed issues they give rise to are summarised in Table 2.1 below.

Table 2.1: High level questions to address

Key question	Other issues / questions to consider
What are the characteristics of a rational investor?	What type of investor is willing to invest in this asset class? Is the investor independent or vertically integrated? Are they considering opportunities across the World, Europe or solely Ireland/ UK? How would they finance an investment in a BNE plant?
What technology choice would the rational investor make?	What size is the plant? What specification (due to operational or environmental factors) does the plant have to meet? What trade-offs between efficiency and cost would they make?

	Which plant would they opt for and how much would that cost?
What would be the rational location for a new peaking plant?	Where can the plant be located? What does that mean for fixed costs? What does this mean for operational costs?
Why would a BNE choose to enter the SEM?	Capacity payment revenues? Infra-marginal rent and ancillary services revenues? What is the required cost of capital?

2.1.2. BNE methodology

The RAs have calculated the fixed costs of a BNE plant entering the SEM since 2007. In each instance that the calculation has been undertaken, a number of the features of the methodology have remained the same. These are:

- The costs of a peaking plant will be established for a site in Northern Ireland (NI) and a site in the Republic of Ireland (RoI) and infra-marginal rent and ancillary services number deducted from that figure.
- Infra-marginal rents earned by a given plant will not be a determinant of the choice of plant (i.e. they will be calculated independently of plant selection).
- The costs of a BNE plant will be calculated for both markets and a decision as to which is best made on cost-benefit grounds.

2.2. Approach

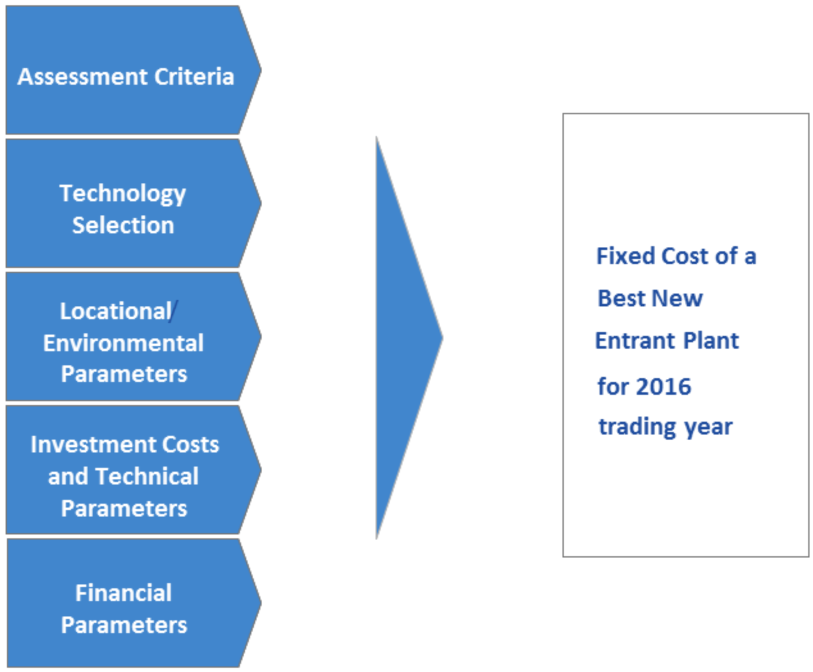
CEPA and Ramboll are aware of the importance of the CPM to existing and prospective investors in generation and the consequences of the size of the CPM pot (the BNE price multiplied by the capacity requirement) for consumers. Our approach is consistent with that used in calculating the BNE price for previous trading years.

The characteristics of the BNE plant for which costs are being derived are:

- The plant is notional and will be delivered into the market in the 2016 trading year. It may be located in either the RoI or NI and use the plant and fuel type which proves most cost efficient.
- The plant will serve the final megawatt of demand, hence it would be expected to operate for a very small proportion of the time.

Undertaking the BNE calculation requires a series of issues to be addressed sequentially, before those elements are combined to develop a series of cost estimates. The high-level approach is shown in Figure 2.1 below.

Figure 2.1: Stylised representation of the elements of the BNE calculation



Our approach, in common with that used in previous years, has been to identify the most suitable technology option and then to calculate the costs of locating that plant at an appropriate site in both NI and the RoI. This then allows two Net Present Value (NPV) calculations to be undertaken and the most cost-effective location to be identified. Within this high-level approach, there are a series of important building blocks.

- The technology choice.
- Associated Engineering, Procurement and Construction (EPC) costs.
- Pre-financial close and other soft costs.
- Financing costs.

These issues are explored in subsequent sections.

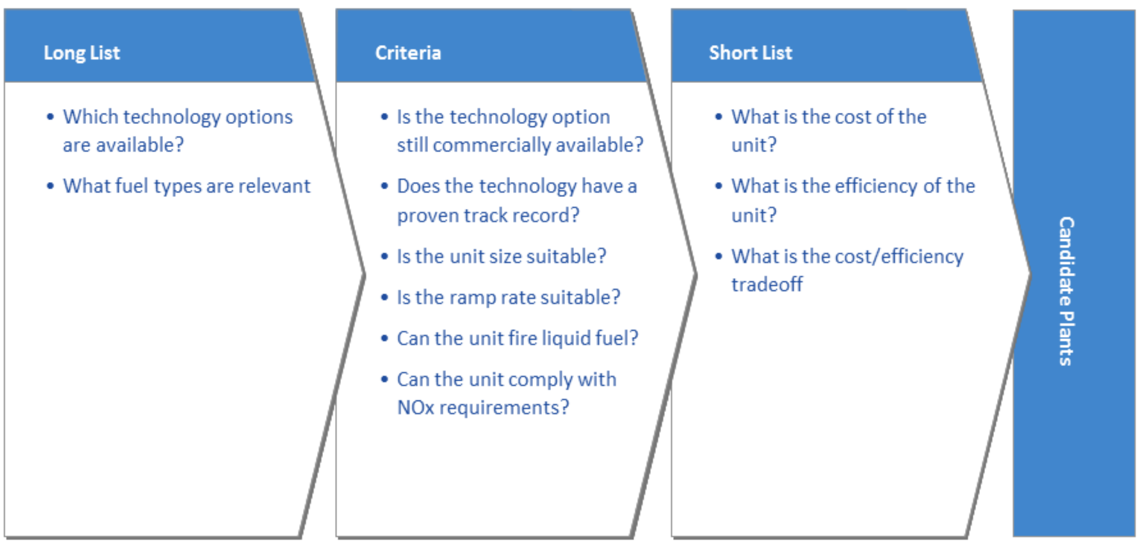
3. BNE Technology selection

This section outlines the process that CEPA and Ramboll have gone through to identify the series of options to be considered as part of the initial "long-list" of candidate plant for the BNE, the criteria that have been used to filter this list towards a "short-list" and the considerations that have led to our final plant technology choice. Annex A provides a more detailed overview of the technology short-list selection process.

3.1. Approach

The approach used to reduce a long-list of options to a short-list is shown in Figure 3.1 below. More detailed explanations are included in the subsections which follow.

Figure 3.1: Approach to identifying technology options



3.2. Long list of options

The starting point for our technology selection process is to develop a long-list of options capturing all available technology options which might reasonably be described as a peaking plant. The relevant plants from this list have been included in Annex A, which is intended to cover the product offerings of the major original equipment manufacturers. The development of the long list for 2016 has drawn from the conclusions previously reached through work on previous BNE reports. Consequently, the following peaking options were not considered for the short-listing process:

- Second-hand plants.
- Interconnectors.

- Aggregated Generating Units.

Additionally, regarding pumped storage schemes (and similarly for compressed air energy storage schemes), for the 2011 calculation these dropped out of the short-listing process on the basis of cost. In practice, this is always likely to be the case, since their inherent operational principle is to run cyclically and thus not “pitched” at serving the final megawatt. As a consequence, they have not been considered for this calculation.

3.2.1. Fuel choice

In the years prior to 2009, the RAs determined that the BNE peaking plant would run on distillate only. The decision was largely due to the costs associated with booking gas capacity and a perceived lack of gas market liquidity.

It was decided that for 2010, GTs under consideration would be evaluated both for distillate firing and for natural gas operation with dual-fuel capability. This decision was driven by a number of factors, including comments received from respondents to the 2010 consultation process and the views expressed by parties which attended a stakeholder seminar, that further developments in the gas market meant gas was a credible fuel source. In particular parties noted that there are several shorter-term products available (noting that a rational investor may not necessarily wish to use such products) in the RoI and there does not appear to be a scarcity of capacity. However parties noted that only an interruptible product exists in NI.

Consistent with the previous calculations we have considered candidate plant firing both natural gas (with distillate back-up) and distillate fuel only.

3.2.2. Environmental requirements

In considering the appropriate choice of technology, we have been mindful of the environmental requirements which a plant would need to meet. The chosen technology needs to be capable of meeting emissions requirements, and since all the potential candidate plant options in the long list are GTs firing low-sulphur fuels, this implies meeting the limits on oxides of nitrogen (NOx) and carbon monoxide.

The Directive on industrial emissions[1] (integrated pollution prevention and control - the Industrial Emissions Directive or IED) came into force on 6 January 2011. Article 30 of the Directive relates to ‘Emissions Limit Values’. For ‘New Plant’ (i.e. those granted a permit after 7 January 2013), the Emission Limit Values are specified under Part 2 of Annex V.

[1] Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control)

The Emission Limit Values for gas turbines (including Combined Cycle Gas Turbines (CCGT)) are shown in Table 3.1 below.

Table 3.1: Emissions limits

Fuel Type	Maximum NOx value (mg/Nm^3)	Maximum CO value (mg/Nm^3)
Light and Middle Distillates as Liquid Fuels	50	100
Gas*	50**	100

Source: Directive on industrial emissions

* For gas turbines (including CCGT) the NOx and CO emission limit values set out apply only above 70 per cent load.

** For simple cycle gas turbines having an efficiency greater than 35% - determined at ISO base load conditions – the emission limit value for NOx shall be 50xη/35, where η is the gas turbine efficiency at base load conditions expressed as a percentage.

However, it should be noted that gas turbines for emergency use that operate less than 500 operating hours per year are not covered by the Emissions Limit Values noted above. In these cases, the operators of these gas turbines shall record the used operating hours. Since, as will be discussed in the later sections of this report, this assessment is based on a plant factor of no greater than 5 per cent (438 hours), the limit of 50 mg/Nm^3 does not apply.

It should also be noted that most OEMs have previously quoted minimum emissions for GTs for NOx, when burning distillate oil, of 42 ppm (~86 mg/Nm^3), design based on historical emissions limits. It is unlikely that the water injection rate could be increased to reduce the NOx emissions down to 50 mg/Nm^3. Design for distillate oil is based on it being an emergency fuel with less than 500 operating hours per year.

3.2.3. General selection criteria for gas turbine plant

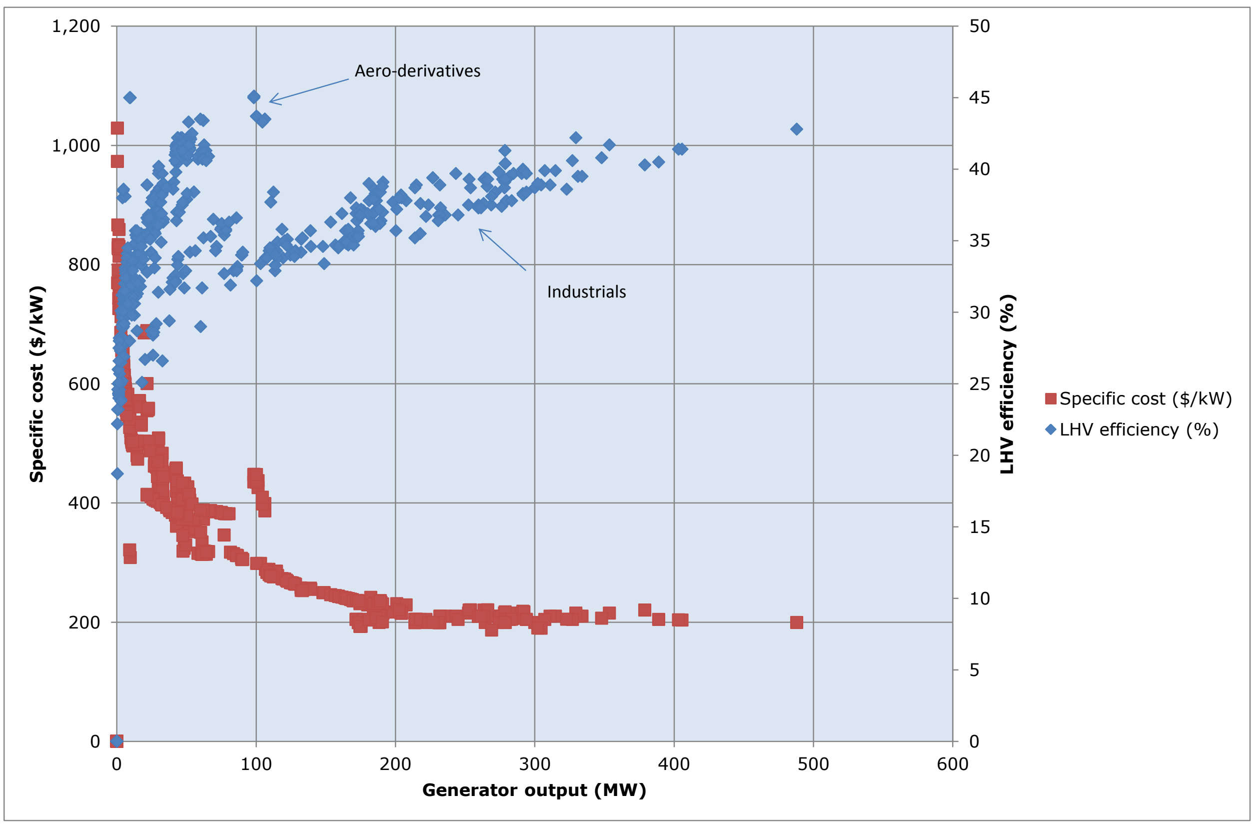
Gas turbines are generally categorised as being industrial (heavy duty) type, or aero-derivative.

Industrial machines are available in a greater range of capacities compared to other plant. They generally have a lower pressure ratio and power density, and are generally larger and less efficient for a given capacity, although the very largest industrial machines (>300 MW) have efficiencies comparable with that of aero-derivative machines. With high exhaust energy they give the highest efficiency in combined cycle. For a given capacity, they generally have a lower specific cost than aero-derivatives. Although they generally have longer start-up times than aero-derivatives, most of the small and medium sized machines can achieve a 20 minute start-up time. Many industrial machines are also capable of burning a wide range of gas and liquid fuels, even heavy and crude oils. Maintenance intervals are dependent on the number of starts and the number of operating hours.

Aero-derivative machines provide the most efficient gas turbines operating in simple cycle. They have a smaller footprint, although because of high pressure ratios might require gas compression. Maintenance outages are generally shorter, and maintenance intervals are dependent on the number of operating hours only. They generally require good quality fuel gas or distillate oil to operate. Start-up times are lower than that for industrial type machines.

Figure 3.2 below gives an indication of the effect of technology and capacity on specific cost and gas turbine efficiency. The chart is based on base reference ISO and cost data from the GTPRO V24 library (includes all models including old versions). The specific cost indicates the relative cost, not the final calculated project cost. This shows that efficiency generally increases with generator capacity, although there is a clear divergence between the aero-derivative machines and the industrial machines. Reducing the generator capacity increases the specific cost, increasing rapidly below 200 MW.

Figure 3.2: Base specific cost and LHV efficiency of GT PRO version 24 gas turbine library



Source: CEPA / Ramboll analysis based on GT Pro

For a particular gas turbine plant project the selection of the gas turbine model will depend on a number of factors, not just the specific cost and efficiency. In general, the selection is governed by selecting the option that provides the lowest lifetime cost, whilst also satisfying the operational requirements of the project. The major factors are summarised in Table 3.2 below:

Table 3.2: General selection criteria for gas turbine plant

Factor	Commentary	Implications for BNE calculation
Unit capacity	The specified capacity of the plant is usually given as a narrow range. This will be dependent on grid requirements, or process requirements, and also redundancy. For example, an operator might require multiple smaller units for operational reasons, although a large single unit would generally provide the lower cost.	The given capacity range of 30 MW to 200 MW is unusually large, leading to a comparison between small and large units which would not normally be in the same market.
Load profile	With the highest efficiency, aero-derivatives are at an advantage with respect to fuel cost. If a large number of starts is also specified, then aero-derivatives might have an advantage because the maintenance intervals are independent of the number of starts.	The operating hours are very low (<500 hours per annum), so fuel efficiency has a less significant effect on the lifetime costs.
Fuel	Many heavy duty machines, particularly older technology, less efficient models, can operate on a large range of gas and liquid fuels.	Fuels are natural gas and distillate oil. Effects performance, but does not give an advantage to any particular type.
Capital cost	Economy of scale means that in general larger capacity machines will give a lower specific cost. For a given capacity, aero-derivative gas turbines have a higher specific cost.	The wide capacity range will favour larger machines.
Regulatory requirements	IED and national planning regulations might affect planning and operational consent requirements, depending on fuel type and plant capacity.	No differentiation in selected gas turbine range.

Source: CEPA / Ramboll

As Table 3.2 shows, there are therefore a range of factors and circumstances that may influence the selection of a particular GT plant internationally. The selection of the BNE is based on a specific set of requirements and criteria which mean that certain types of GT are more appropriate for the BNE in the context of the SEM.

The short-listing criteria we specifically apply to select the BNE peaking plant, are discussed in the section which follows.

3.2.4. Short-listing criteria

Having developed an extensive long-list that covers various technology options and fuel types, we have then applied a series of short-listing criteria. These criteria are designed to reflect considerations which a rational investor may consider in making a decision on technology as well as the requirements of the Transmission System Operators (TSOs).

CEPA and Ramboll consider that the assessment criteria used in the previous calculation remain fit-for-purpose and we have therefore undertaken our initial short-listing by applying the pass/fail criterion set out in Table 3.3 below.

Table 3.3: Filter criteria

Pass/fail criterion	Rationale
Is the technology option still commercially available?	The plant needs to be being manufactured to be credible. We have verified whether this is the case by contacting manufacturers.
Does the technology have a proven track-record (typically defined as three examples of over 8,000 running hours for industrial units or 500 starts for aero derivatives)?	While this is a proxy for the view that an insurer would take of a plant, we note that in 2010 we included an additional plant based on market feedback.
Are the unit sizes between 30 and 200MW?	At the kick-off meeting of 24th February, attended by the RAs, CEPA and Ramboll, the possibility of extending the gas turbine capacity range up to 299 MW was discussed. Installing a single large gas turbine with relatively high efficiency, and low specific costs has some advantages for a rational investor, and for a specific site should be considered. However, further investigations have shown that although they are capable of starting within 20 minutes under certain circumstances, the normal cold start is greater than 20 minutes. They were therefore not short listed.
Can the technology option ramp up to full load in less than 20 minutes?	In previous BNE calculations, the TSOs identified this as a necessary operational criterion for a peaker. We note views that this time may need to fall as wind penetration rises in the SEM but have retained the previous 20 minute assumption. We welcome stakeholder views on whether this remains appropriate.
Can the technology option fire liquid fuel?	RoI has an obligation on gas fired power stations to provide secondary fuel for backup. If gas fired, the peaker would need to be capable of meeting this obligation.
Can it meet NOx requirements?	As noted above, the plant must be capable of meeting environmental legislation which is reflective of its expected pattern of operation, but refer Section 3.2.2 with respect to operating hours.

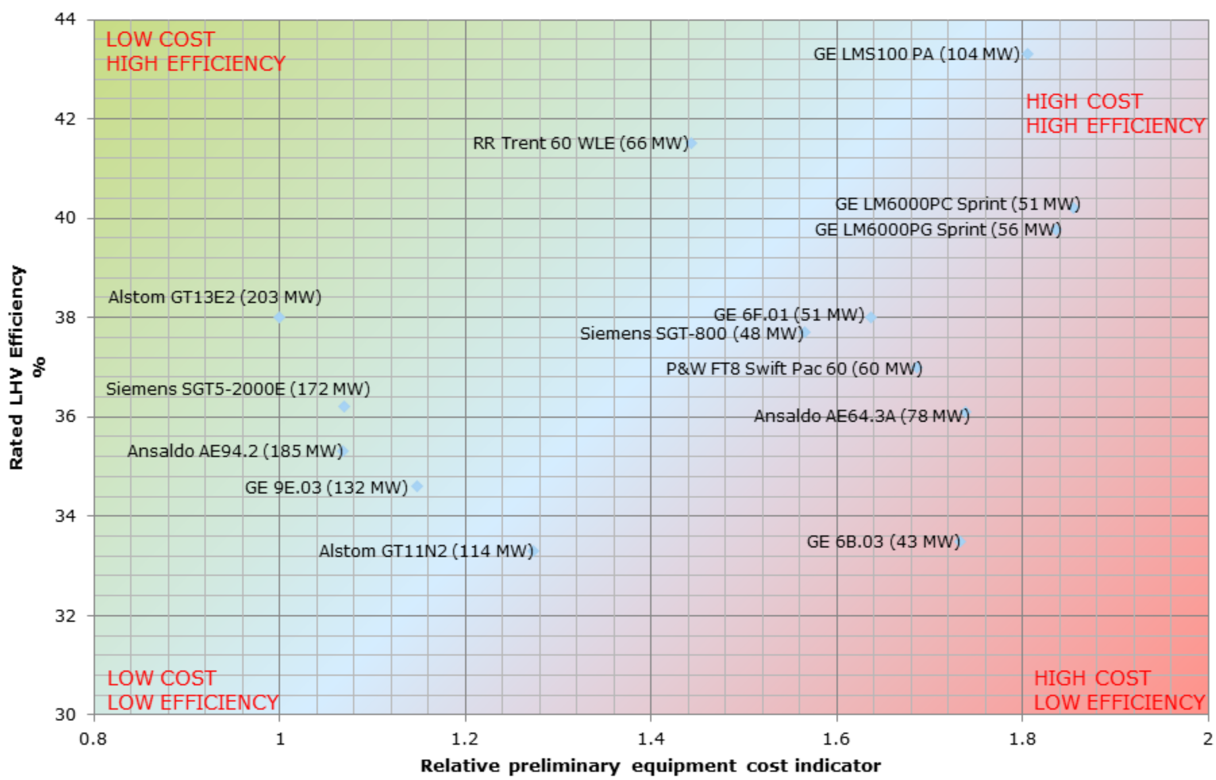
3.3. Initial filter

On the basis of the filtering process outlined above, we identified a series of plant which fulfilled these criteria. In our previous year (BNE 2013) report, we then considered the remaining options' equipment cost, based on the basic gas turbine costs from the latest version of GT Pro (version 21). These are generally in line with GTW Handbook specific costs. We again used this principle, using the latest version of GT Pro (24). These costs form the basis for the PEACE costs described in Section 3.4.2.

For the BNE consultation process for the 2010 trading year calculation, feedback from generators indicated that given that the peaking plant would only be expected to run a small number of hours (2% to 5%), the capital cost would be a much more relevant consideration for an investor than the plant's efficiency. We agree with this comment and this was reflected it in the approach taken in short-listing plant for the 2012 and 2013 trading years, and the same philosophy has been used for the 2016 trading year.

Figure 3.3 below shows the cost and efficiency trade-off for various potential candidate plants. The cost indicator is relative to the minimum specific cost.

Figure 3.3: ISO efficiency and equipment cost trade-off for front-running plant meeting filtering criteria



Source: CEPA / Ramboll

The plot illustrates the fairly significant number of options which passed our initial filter. Ideally, the machines would be in the "low cost, high efficiency region". As expected from the discussion in Section 3.2.3 the medium sized (100 MW – 200 MW) industrial machines provide the lowest specific cost. The Alstom 13E2 as before has the lowest specific cost, and the highest efficiency of the industrial machines. The aero-derivatives show high efficiency at high cost. The smaller industrials show low to medium efficiency at relatively high cost.

Table 3.4 gives a brief description of the characteristics of each turbine model in Figure 3.3. As can be seen, the machines have different characteristics, which, depending on the project requirements, as described in Table 3.2, will determine candidate plant. For the BNE calculation, fuel flexibility provides no advantage, and there is no specific requirement for multiple units, so it is to be expected that the larger plant will be at an advantage.

Table 3.4: Gas turbine model characteristics

Gas turbine model	Characteristics
Alstom GT11N2	Medium industrial machine, with good fuel flexibility.
Alstom GT13E2	Medium/large industrial machine, relatively high efficiency, generally for operation on good quality gas and distillate oil.
Ansaldo AE64.3A	Originally developed under licence with Siemens. Medium industrial machine, typically burning natural gas and/or distillate oil in smaller CCGT plant, or for CHP.
Ansaldo AE94.2	Originally developed under licence with Siemens, Ansaldo's version of Siemens' SGT5-2000E. Competes with 13E2 in terms of capacity, but less efficient in simple cycle. Silo combustors give it excellent fuel flexibility.
GE 6B.03	"Workhorse" small industrial machine, low efficiency. Excellent fuel flexibility.
GE 6F.01	Originally marketed as the 6C, upgraded and renamed. "F" class machine for operation on natural gas providing good CCGT efficiency <100MW, and for industrial/cogeneration.
GE 9E.03	"Workhorse" medium industrial machine, low efficiency. Excellent fuel flexibility.
GE LM6000PC Sprint	Typical small/medium aero-derivative, providing fast start and high efficiency on natural gas or distillate oil, operation in simple cycle and for cogeneration.
GE LM6000PG Sprint	Typical small/medium aero-derivative, providing fast start and high efficiency on natural gas or distillate oil, operation in simple cycle and for cogeneration.
GE LMS100 PA	Largest and most efficient aero-derivative with typical aero-derivative characteristics.

Gas turbine model	Characteristics
P&W FT8 Swift Pac 60	Typical small/medium aero-derivative, providing fast start and high efficiency on natural gas or distillate oil, operation in simple cycle and for cogeneration.
Siemens SGT5-2000E	Medium/large industrial machine. Competes with 13E2 in terms of capacity, but less efficient in simple cycle. Silo combustors give it excellent fuel flexibility.
Siemens SGT-800	Small/medium industrial machine, high efficiency for its capacity and type. Good for cogeneration and industrial applications.
Siemens Trent 60 WLE	Typical small/medium aero-derivative, providing fast start and high efficiency on natural gas or distillate oil, operation in simple cycle and for cogeneration.

Source: CEPA and Ramboll

3.3.1. Candidate plants

The candidate GTs for the 2013 trading year calculation were:

- 1 x Siemens SGT5-2000E
- 1 x Alstom GT13E2
- 1 x Ansaldo AE94.2

As in previous years, given the criteria, where high efficiency provides little cost benefit, the larger industrial type machines with the lowest specific cost are the most likely candidate units. With significantly lower capacity, the GE 9171E and Alstom 11N2 are significantly more expensive and less efficient than the other industrial type units (SGT-2000E, AE94.2, Alstom 13E2) and so are still discounted.

Water injection is used when firing distillate oil to reduce NOx emissions. It has the effect of increasing output, but lowering the efficiency. Although not necessarily required in this case for emissions control (see Section 3.2.2), as in previous years, water injection was used for power augmentation for the three candidate machines when operating on distillate oil. The AE94.2 combustion system cannot operate with water injection while running on gas; however, the GT13E2 can benefit from water injection for power augmentation on gas operation and this has been included in the modelling. Siemens' own performance modelling program, SIPEP, was used to model the SGT5-2000E, allowing water injection when operating on gas, and was used in the evaluation.

We then proceeded to conduct a more detailed assessment of the costs of each of the candidate plants.

3.4. EPC costs and performance

This section briefly considers changes in EPC market conditions and outlines our approach to EPC cost estimation.

3.4.1. State of the EPC gas turbine plant market

Due to the specialised nature of the equipment there are a limited number of suppliers of the equipment necessary to construct new generation capacity that might be generally expected to be suitable as BNE peaking plant. In recent years there has been further consolidation in the market:

- MHI and Hitachi merged their thermal power business;
- Siemens bought the gas turbine and compressor business of Rolls Royce; and
- Alstom is selling its energy business including gas turbines to GE, subject to EU approval.

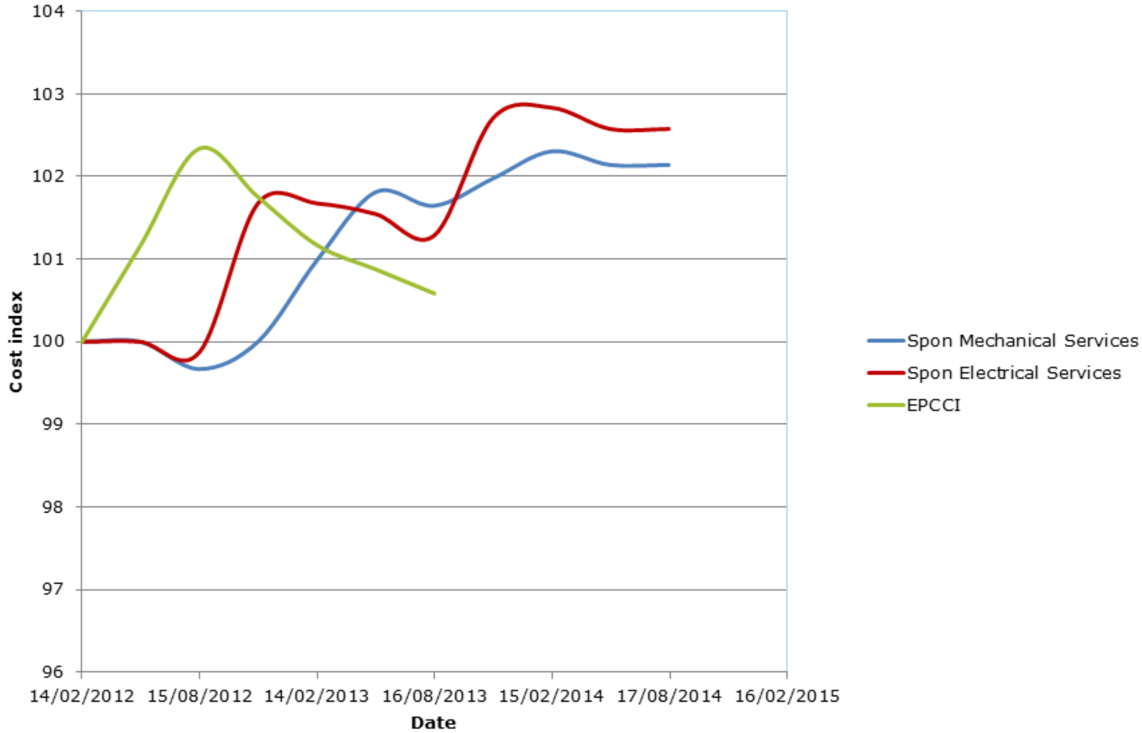
Manufacturers continue to add new models and upgrade older models. Since 2009, around 30 new models have been introduced. Upgraded models include those included as candidate plants in the 2013 calculations; although some upgrades are relatively minor, some include major changes, utilizing technology from existing machines. In particular, manufacturers are looking to develop more flexible machines with faster start times, and higher ramp rates, both industrial and aero-derivative gas turbines.

The cost of gas turbine plant has been relatively low in recent years, but, particularly led by low gas prices in the USA, and environmental pressures and the introduction of fluctuating renewable generation, we would expect market demand, and hence price, particularly of simple cycle plant, to increase in forthcoming years. Figure 3.4, below, shows material and labour cost indices from Spon's 2015 Price Books Update, and the European Power Capital Cost Index (EPCCI) (non-nuclear)[2] , each adjusted to give Q1 2012 = 100. Figure 3.5 shows UK power plant costs for different plant capacities[3]. The Spon's indices indicate increases in project costs of around 2% since 2012. The EPCCI data shows a slight reduction, but flattening off of prices up to 2013. The GlobalData chart (Figure 3.5), shows a flat trend (we have presented average prices for only the larger plant capacities for more recent years, as the smaller size categories are considered less relevant to the BNE).

[2] IHS Indexes

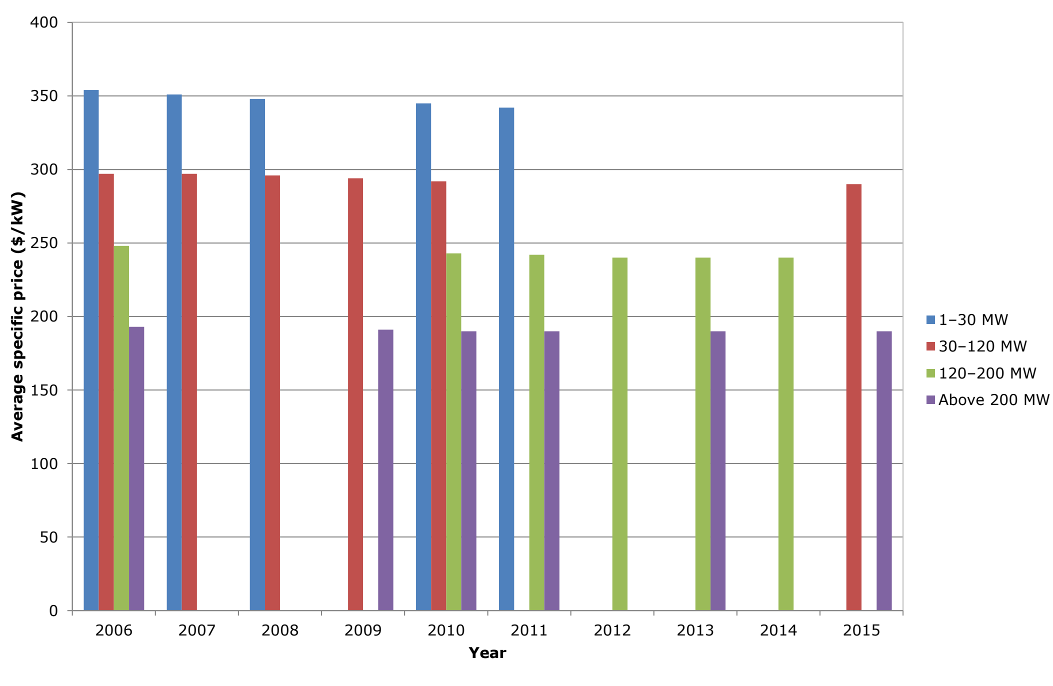
[3] GlobalData, Power eTrack, Power Plant Database, Capacity and Generation Database [Accessed on: July 25, 2014]

Figure 3.4: Material, labour and cost indices



Source: CEPA/Ramboll

Figure 3.5: UK GT Plant Costs



Source: CEPA/Ramboll

3.4.2. Approach to EPC cost estimation

To maintain continuity, and provide a good comparison with previous years, the approach to cost estimation has remained the same.

The shortlisted plants were modelled using the latest updated version of GT PRO and its associated cost estimating program PEACE. In addition, reference plant was modelled to provide further calibration of the plant cost estimations.

As in previous years, the, average output degradation over the economic lifetime of the plants has been set at 2.5% and 2.0% for distillate and gas operation respectively. An average lifetime inlet pressure draught loss of 6 mbar has been applied. The resultant EPC costs are given in Table 3.5, below, using NI as the basis as there is a slight difference in EPC costs between jurisdictions due to differences in transmission voltages between NI and ROI. The costs are shown together with the average lifetime net power output of the candidate plant options. These outputs are based on a water injection to fuel mass flow ratio of 1:1 where possible (and where not provided by the OEMs).

As in the previous calculation, at the lowest ambient temperature when the gas turbine output is highest, the water injection rate was limited by the power limit. Once the power limit is reached, any additional water injection would merely reduce the firing temperature and increase the heat rate. At higher ambient temperatures, the water injection rate can be increased when the GT attains full load.

Table 3.5: EPC cost estimate and power output for short-listed plants in NI.

Plant Type	Fuel Type	Average Lifetime Output (MW)	EPC Cost (€m)[4]
ALS GT13E2	Distillate	195.7	94.5
	Dual	203.9	95.6
AE94.2	Distillate	166.5	84.3
	Dual	167.7	82.7
SGT5-2000E	Distillate	178.6	91.1
	Dual	180.4	91.4

Source: CEPA/Ramboll

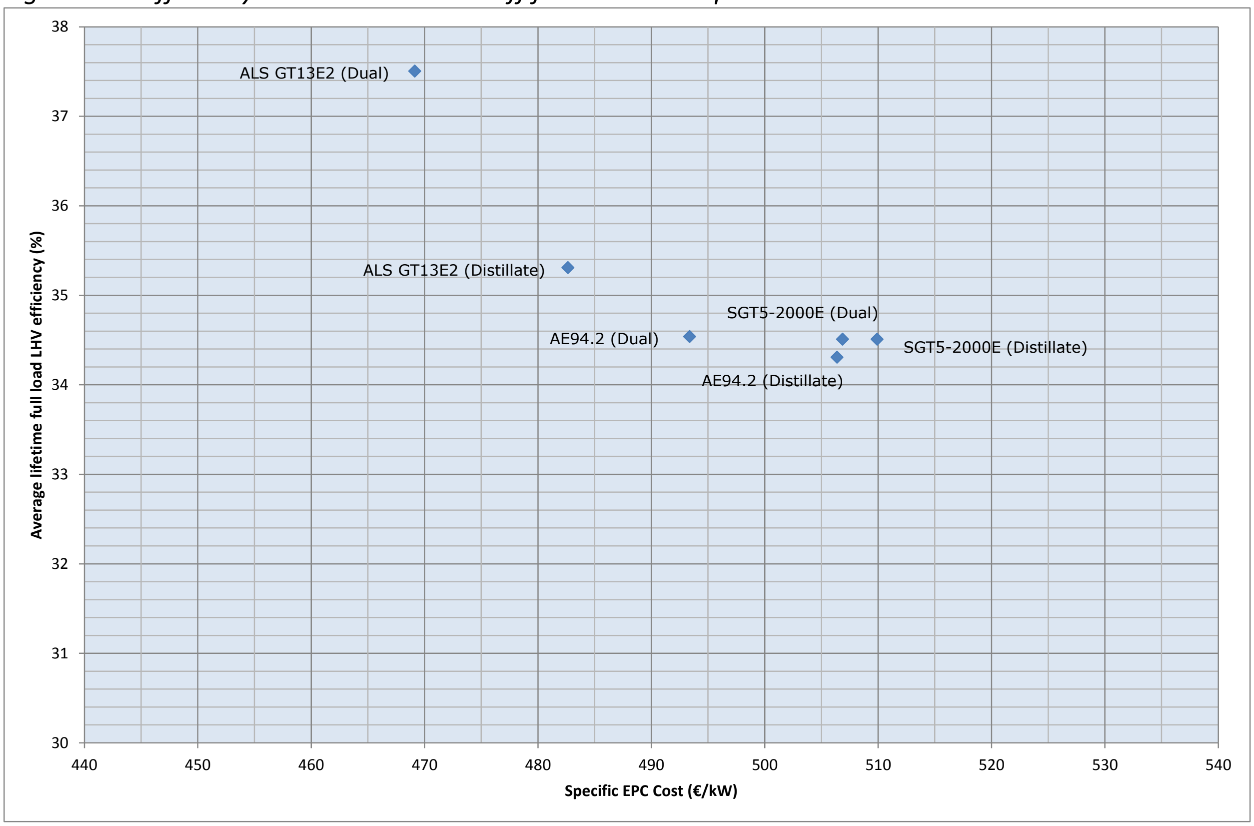
As in the previous BNE calculations, the default cost multipliers were used in the GT PRO/PEACE modelling. These provided good estimates for the reference plant model. The resultant costs

[4] Please note that approximately 5% contingency is included as an integrated part of the contractor price.

are approximately 2% higher than in the previous (2013) BNE calculation. This is consistent with the market analysis provided in Section 3.4.1 above.

To compare these options on a specific EPC cost basis, the costs are plotted against efficiency in the chart below (Figure 3.6). Average efficiency degradation over the economic lifetime of the plants has been set at 1.25% and 1.0% for distillate and gas operation respectively, as in the previous BNE calculation.

Figure 3.6: Efficiency and EPC cost trade-off for short-listed plant



Source: CEPA/Ramboll

3.5. Chosen technology option

Based on the assessment above, EPC costs per kW for the candidate plants, firing both gas and distillate, are shown in Table 3.6.

Table 3.6: Specific EPC cost estimates for short-listed plants in NI.

Plant Type	Fuel Type	EPC Cost €/kW
Alstom GT13E2	Distillate	482.6
	Gas	469.1
AE94.2	Distillate	506.4
	Gas	493.4
1 x SGT5-2000E	Distillate	509.9
	Gas	506.9

Source: CEPA/Ramboll

On the basis of the approach outlined above, in CEPA/Ramboll's opinion, it is likely that the **BNE GT for 2016 is an Alstom GT13E2**. This plant has a capacity of 202MW (198.0MW with 2 per cent average degradation) in dual fuel configuration.

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

3.5.1. Technical assumptions for selected plant

The following has been built in to the performance and cost models for the 1 x ALS GT13E2 plant option:

- Ambient conditions at the grid's winter peak.
- Transmission voltage of 110kV for NI and 220kV for the RoI.
- Distillate storage for both distillate options of 3.5 days at maximum plant load and 3 days for dual fuel option to reflect secondary fuel obligation in Ireland.
- Water storage and treatment capability for 3.5 days of water injection at 1.18:1 water to fuel ratio (mass basis) at maximum plant load.
- 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 barG.
- Average lifetime draught losses of 6 and 12.5 mbar for inlet and outlet respectively.

- Average lifetime degradation for power output and heat rate of 2.5% and 1.25% respectively for distillate option and 2% and 1% for gas operation.

Initial views

- **As the BNE plant will run for a very limited number of hours, cost is the key driver of plant choice.**
- **On this basis, the Alstom 13E2 appears (as in the previous trading year) to be the chosen GT.**
- **This plant will be assessed based on gas and distillate firing for sites in NI and the RoI.**

4. COST ESTIMATES

This section considers the investment and ongoing cost estimates associated with the BNE plants in NI and the RoI.

4.1. Types of cost

In this section we consider:

- Investment costs, which have been sub-divided as follows:
  - EPC contract and timeframe
  - Site procurement costs
  - Electrical interconnection costs
  - Gas and make-up water connection costs (where applicable)
  - Owner's contingency
  - Financing, Interest During Construction (IDC) and construction insurance
  - Up-front costs for fuel working capital
  - Other non-EPC costs
  - Market accession and participation fees
- Recurring operational costs, which have been sub-divided as follows:
  - Transmission and market operator charges
  - Operation and maintenance
  - Insurance
  - Rates
  - Working fuel capability

We discuss each element in turn below.

4.2. Location of the BNE plant

In common with the approach undertaken by the RAs in previous years, this section considers the costs associated with locating a BNE plant in either relevant jurisdiction. As we noted in our previous BNE reports, there are a number of conventional generation plants expected to enter the market in the next ten years. Sourced from the All-Island Generation Capacity Statement

(2014-2023), Table 4.1 lists thermal generators that have signed agreements and confirmed dates to connect to the island over the next ten years.

Table 4.1: Confirmed contracted conventional generation capacity to the island up to 2023

Plant	Export capacity
Great Island CCGT	431
Dublin Waste to Energy	62
Nore OCGT	98
Suir OCGT	98
Cuilleen OCGT	98
Ballakelly CCGT	445

Source: EirGrid/SONi

As in previous years, for the RoI we consider that a BNE investor would be able to obtain agricultural land, probably close to a relatively unconstrained part of the transmission network.

In previous years, we had assumed that the site of the former Belfast West power station is the appropriate location in NI. However, based on discussions with the RAs, we understand that this site may no longer be available. For these reasons we no longer consider specific site costs for the NI BNE (see discussion below) and adopt the same approach that is used in the RoI.

4.3. Investment costs

This section considers investment costs associated with likely sites in the RoI and NI.

4.3.1. EPC contract price and timeframe

As outlined in the Section 3, the Alstom GT13E2 was modelled in GT PRO according to the assumptions given in Section 3.6.1 and no uplift was applied to the EPC cost estimate. The outcome of this process is shown in Table 4.2 below for the two jurisdictions.

Table 4.2: EPC cost estimates for NI and RoI

Plant	Fuel type	EPC Costs (€ million)
NI	Distillate	94.5
	Dual	95.6
RoI	Distillate	95.7
	Dual	96.9

The reason for the difference in the NI and RoI cost estimates is due to the difference in costs associated with the differing transmission voltages. The period over which the Alstom GT13E2 plant is expected to be built, from financial close to plant hand-over, has, in common with previous years, been estimated at 18 months.

4.3.2. Site procurement costs in RoI

In the 2013 BNE report, we retained the notional rate of €150k/acre for suitable greenfield land in the RoI. This was approximately a 50% decrease compared to the value used for our 2010 BNE report. While we noted it might be possible to secure a suitable site at a lower rate per acre, any affected landowner is likely to view a power station as industrial development (whether or not they had any likelihood of securing consent for such a use) and/or are likely to argue for injurious affection (diminution in value of land held with land taken).

We propose to retain the notional rate of €150k/acre for the 2016 BNE calculation as market commentary suggests that agricultural land values have stabilised and we have seen no firm evidence to suggest that there has been a significant rise or fall in land values since developing our 2013 estimate. We would welcome stakeholders' views and evidence on whether this assumption continues to be appropriate.

4.3.3. Site procurement costs in NI

Our previous site procurement costs for a site in NI was based upon the BNE being based at the Belfast West site. From discussions with the RAs, we understand that it is possible this site may no longer be available.

There is a fee farm grant[5] for sixteen acres for electricity generation available at the Belfast West site and our understanding is that a license agreement has been established for an electricity plant being developed on the site, although contracts have not been signed. The plant we understand is also considering an alternative site at Belfast Harbour (which has two alternative sites where a power plant could potentially be located).

This potentially means that one of the Belfast West or Belfast Harbour sites *could* potentially be available for the BNE investor. However, given the uncertainty of which site may be available, for this year's calculation, we have followed the same approach as adopted for RoI – i.e. we assume a notional site, which is also assumed to be a rural location.

We have then based our assessment of site procurement costs on the land values in NI as a whole. We take our RoI assumption on site procurement costs as a base and have adjusted for the relative difference in agricultural land values between NI and RoI. Agricultural land in NI appears to be 25% greater per acre than in the RoI. This gives a rate of €187.5k/acre for the

---

[5] Under UK and Irish law, a fee farm grant is a type of land ownership typical in cities and towns.

BNE for NI, with the same uplift applied. We would welcome stakeholders' views and evidence on whether this assumption is appropriate.

The location of the BNE is one of the key inputs to the calculation and we note has an impact on other cost inputs, including electrical connection costs, transmission network charges and other ongoing costs faced by the plant.

We therefore welcome stakeholders views on what should be the appropriate location of the BNE in NI and, in particular, whether a more prudent assumption would be to assume that the plant is located at either Belfast West or Belfast Harbour. Based on previous BNE calculations, locating the BNE either at Belfast West or Belfast Harbour is likely to increase the *site procurement* costs of the plant, but may reduce other investment costs (such as water and electrical connections) given existing infrastructure that services these sites.

4.3.4. Summary of site procurement costs

Table 4.3 summarises our assessment of land costs for the BNE plant.

Table 4.3: Assessment of land costs

Location	Fuel type	Required area (m2)	Estimated site cost (€)
NI	Distillate	20,700	€959,078
	Dual	20,500	€949,811
RoI	Distillate	20,700	€767,262
	Dual	20,500	€759,849

Despite additional equipment being required for the dual fuel scenarios, the additional half a day's storage of liquid fuel for the distillate scenarios results in slightly larger land areas required (see Section 4.3.9 for a discussion of fuel storage requirements).

4.3.5. Electrical connection costs

A significant driver of the costs of a site is the electrical connection costs the site would face. The transmission voltages for RoI and NI are 220kV and 110kV respectively.

For NI, as described above, we are no longing calculating the generator connection for the Belfast West site. Our approach is to use the cost estimates provided in the SONI Transmission Charging Methodology Statement (2009) for a hypothetical connection design. We then present this in Euro terms, based on modelling exchange rate assumption (see Section 7).

However, without knowing the actual site of the BNE and the local network which the plant will need to connect into, it is difficult to establish assumptions on the connection arrangements. For example, with the plant assumed to be located in a rural location, it is possible an overhead line (OHL) solution could be built. However, given the planning impacts of building an OHL, a cabling solution may instead be considered a more preferable solution, as although it will be considerably more expensive to purchase equivalent lengths, it will be much quicker to install, helping to facilitate timely connection of the BNE plant.

For this initial report, given the assumption of a notional NI BNE site, we have assumed a 110kV connection based on construction of a 110kV Double Circuit Steel Tower (the OHL is assumed possible given the notional *rural* site for the BNE plant) and have also included the cost of seven circuit breakers at a new NIE substation.

Note that if the Belfast West site (as in recent calculations) was used as the site for the NI BNE investor, then a similar estimate of electrical connection costs could be applied as in previous years (we have been informed by the RAs that electrical connection costs would be incurred at Belfast West due to sun-setting[6] of the adjoining substation to the site). Alternatively, if the Belfast Harbour location was chosen by the BNE investor, then standard electrical connection costs would be incurred if located on the actual harbour land, but if the plant was located slightly north[7] this would be likely to incur extra cabling, with a resulting increase in costs.

However, as we have adopted a notional rural site for the NI calculations, these considerations currently do not impact on the BNE's costs. They would do if either site was considered the better location for the BNE investor (see discussion on site procurement costs above).

For the RoI site, we have adopted the same approach as for the 2013 BNE calculation decision paper. This assumes a 220kv connection design adjusted for a 4 km connection (i.e. 2km per leg of loop) with the costs of the connection based on the CER's most recent published standard transmission connection charges.[8]

The resulting estimate of electrical connection costs for the BNE in both jurisdictions is summarised in Table 4.4 below.

Table 4.4: Electrical Connection Cost Estimates

Location	Electrical Connection Costs (€)
NI	€10,529,100
RoI	€6,970,000

Given the uncertainty of the requirements of the BNE's electrical connection, particularly the requirements which apply to the notional NI BNE site, this is a cost element we intend to

[6] Meaning the existing substation will be replaced.
[7] To the Dargan/Herdman site.
[8] http://www.cer.ie/docs/000837/Standard%20Transmission%20Charges%202014%20%28CER13303%29.pdf

investigate further, including with SONI. We welcome stakeholder feedback on the appropriateness of the assumptions used to derive our cost estimates.

4.3.6. Gas and raw water connection

We have also estimated the costs associated with securing a water supply and a connection to the gas network (where applicable). For the water connection, the total cost of an installed 1km pipeline, 4 inches in diameter, has been assumed for RoI. This cost was estimated using GT MASTER/PEACE. In recent BNE determinations, the Belfast West site had an existing water connection. However, we now require an estimation for the whole of NI. We take the same approach as adopted for RoI.

We have used the same gas connection costs for NI and the RoI as in our report for the RAs for the 2013 BNE calculation. These are based on estimates received from Gaslink in developing the BNE price for 2010 (revised in the determination of the pipeline and connection costs for a 2km (rather than 1km) pipeline for NI and RoI).

Table 4.5: Gas and raw water connection costs

Location	Cost of water connection (€)	Cost of gas connection (€)
NI	€490,000	€3,620,000
RoI	€490,000	€3,620,000

4.3.7. Owner's contingency

Owner's contingency covers such things as project delays due to force majeure events and the resulting lost revenue, additional civil works costs due to unexpected sub-terrain, and claims relating to interface problems. Based on our experience, 5% of the value of the EPC cost has been attributed to owner's contingency (in addition to the contingency within the EPC price).

Table 4.6: Owners contingency

Location	Fuel Type	Owners contingency (€)
NI	Distillate	€4,725,000
	Dual Fuel	€4,780,000
RoI	Distillate	€4,785,000
	Dual Fuel	€4,845,000

4.3.8. Financing, interest during construction and construction insurance

Financing and construction insurance costs have been estimated as a proportion of EPC costs based on CEPA/Ramboll's past experience. For interest during construction (IDC) we have used the same approach as our previous BNE report and calculated the interest on the loan amount drawn down in proportion to the gearing ratio prior to the plant earning revenues. Similar to previous years we have not assumed any premium on the debt during the construction phase.

Table 4.7: Financing, interest and insurance costs

Element	Total cost for distillate (€)	Total cost for dual fuel (€)
Financing NI	€1,890,000	€1,912,000
Financing RoI	€1,914,000	€1,938,000
IDC NI	€848,614	€880,483
IDC RoI	€1,108,885	€1,152,878
Construction Insurance NI	€850,500	€860,400
Construction Insurance RoI	€861,300	€872,100

4.3.9. Fuel working capital assumption

It is necessary to include the costs of fuel which needs to be held to comply with various regulatory policies as a BNE capital cost. In the RoI this cost is driven by the secondary fuel obligation. For gas plant this states:

> *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.*[9]

It is our understanding that secondary fuel requirements in NI remain under review by DETI as part of the redrafting of the NI fuel security code.[10] In the absence of further information it is assumed that the above obligation would be applicable in either jurisdiction.

At the outset of the project an investor will need to pay for this fuel. We have therefore assumed an initial fuel storage fill cost of €3.63m for a distillate plant and €3.06m for a dual fuel plant, based on a requirement to run for 72 hours full load, as well as an additional 0.5 days of commercial running for distillate plants and an oil price of US$58.13/barrel[11]. It is assumed that this fuel is sold back at the end of the plant life. Consistent with the 2013 BNE decision, excise duty has also been added to fuel costs for NI plant.

Our cost estimate for fuel working capital is provided in Table 4.8 below.

[9] Secondary Fuel Obligations on Licensed Generation Capacity in the Republic of Ireland

[10] http://www.detini.gov.uk/deti-energy-electricity-12

[11] Oil price used was ICE Brent Crude as traded on 12th March 2015 (sourced from CEPA Bloomberg subscription).

Table 4.8: Initial fuel working capital (NI)

Element	Total cost for distillate (€)	Total cost for dual fuel (€)
Fuel working capital	€3,638,868	€3,057,014

4.3.10. Other non-EPC costs

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

We retain the assumptions used in previous BNE calculations based upon cost benchmarking with, the percentage of EPC cost allocated to Other non-EPC costs being 9.0%.

Table 4.9: Other non-EPC costs

Location	Fuel type	Other non-EPC costs
NI	Distillate	€8,505,000
NI	Dual fuel	€8,604,000
RoI	Distillate	€8,613,000
RoI	Dual fuel	€8,721,000

4.3.11. Market accession and participation fees

The BNE plant will also need to pay market accession and participation fees before beginning operating. Participation fees have been reduced slightly compared to the previous year costs as shown in Table 4.10 below.[12]

[12] SEMO Tariffs and Imperfection Costs October 2014-September 2015

Table 4.10: Market accession and participation fees

Type of charge	Basis for calculation	Current charge	Previous value (2013)
Accession fee	Fixed charge to cover costs of assessing application	€ 1,044	€ 1,115
Participation fee	The fee payable with an application to register and become a participant in respect of any Unit.	€ 2,610	€ 2,788

4.4. Recurring cost estimates

In addition to identifying investment costs, it is necessary to consider the recurring costs that the BNE plant will face. This includes:

- market operator and electricity transmission use of system charges;
- operation and maintenance costs;
- insurance; and
- business rates.

In previous BNE calculations, for the dual fuel plant, we included estimates of the gas transportation charges that the BNE (gas fired) plant would incur, as these were considered a fixed cost for the peaking plant.

Following the SEM Committee's 2014 decision[13] on the treatment of gas transportation capacity costs in the bidding code of practice for the SEM, however, we understand gas transportation costs are now expected to be included in generators energy market bids. Gas transportation costs have, therefore, been excluded from the BNE calculation for this year.

4.4.1. Electricity transmission and market operator charges

Market operator charges

As part of its role in the administration of the market, there are charges which the SEMO must levy in order to recover its own allowed costs and allowed market related costs.

These charges consist of:

- the Imperfections Charge,

[13] See SEM Committee (2014): 'Decision paper on Treatment of Gas Transportation Capacity Costs and Modification to the Bidding Code of Practice'

- the Market Operator charges, and
- the generator under test tariff.

For the purposes of the BNE, only Market Operator charges are relevant.

Table 4.11 provides our estimate of the Market Operator charges which would apply to the BNE peaking plant. We note that SEMO's Market Operator charges have fallen relative to the last BNE calculation in 2013.

Table 4.11: Market operator charges

Type of charge	Charge amount	Total Cost
Fixed market operator tariffs	€ 47.00/MW	Distillate - €9,198 Dual - €9,583

Electricity transmission Use of System charges

The development of harmonised all-island electricity transmission generator use of system charges was an objective stated in the original 2005 SEM high level design. A harmonised regime came into force in 2012[14] following the SEM Committee's decision paper on all-island generator TNUoS charges.

For the BNE 2016 calculation, we have used:

- the average locational G-TNUoS tariff that applies today for existing NI sites; and
- the average locational TNUoS tariff that applies today for existing RoI sites,

for the notional NI and RoI site respectively.[15] Our estimates of electricity transmission generation charges are summarised in Table 4.12 below.

Table 4.12: Generator TUoS charges

Location	Fuel Type	TUoS charge (€)
NI	Distillate	€807,634
	Dual Fuel	€841,475
RoI	Distillate	€1,359,144
	Dual Fuel	€1,416,094

[14] SEM Committee (2012): 'All-island Generator Transmission Use of System (TUoS) Charges

[15] Sourced from EirGrid 14/15 Proposed Generator TUoS v10.

4.4.2. Operation and maintenance costs

Similar to the previous BNE calculation, the plant is assumed to be manned by multi-skilled staff capable of operating the plant and performing minor maintenance activities not covered by the Long Term Service Agreement (LTSA). Five shifts of two multi-skilled operators have been assumed, together with an allocation for general and administration costs, amounting to an estimated €480,000 per year. Consistent with the approach used in previous years, any differences between locations (such as, for example, labour rates) have not been considered.

The fixed annualised LTSA maintenance costs of the plant are based on the minimum maintenance regime for the GT13E2 recommended by Alstom for units running less than 3000EOH per year. Recent LTSA costs for a GT13E2 plant have been reviewed and there does not appear to be a significant move in the prices. For the distillate option, the fixed annualised LTSA maintenance costs amount to an estimated €1,460,000 and for the dual fuel option, €1,490,000. Since the fixed LTSA payments have been anticipated to cover the minimum recommended maintenance regime for low-utilisation plants, it has been assumed that the cost of full parts replacement at 48,000EOH is accounted for through a variable maintenance cost that is bid into the market.

Table 4.13: Fixed operation and maintenance costs

Fuel type	O&M Costs (€)
Distillate	€1,940,000
Dual fuel	€1,970,000

4.4.3. Insurance

Our insurance estimate is based on a percentage of EPC costs and is based on past experience. As with the previous BNE report, we have assumed insurance costs are 1.6% of EPC costs.

Table 4.14: Insurance costs

Fuel Type	NI (€)	RoI (€)
Distillate	€1,512,000	€1,531,200
Dual Fuel	€1,529,600	€1,550,400

4.4.4. Business rates

Business rates are annual taxes paid on the value of a property. They are paid on a local, and in NI, also regional basis.

We have used the same approach to determining business rates as used in previous years for the RoI. We have retained the valuation formulae whereby the plant is valued at €115/MW and the multiplier rate on valuation is 68. From our research we have not found clear evidence to consider it appropriate to revise these assumptions.

For NI, we have used the valuation formula from the "Valuation (Electricity) Order (Northern Ireland) 2003", which sets out how electricity generating stations are valued for tax purposes. As the BNE site is no longer based at Belfast West, we have used an average of regional rates across NI for this year's calculation rather than the rate for Belfast only.[16]

Table 4.15: Annual business rates

Fuel Type	NI (€)	RoI (€)
Distillate	€752,506	€1,532,372
Dual Fuel	€784,036	€1,596,580

4.5. Summary

The tables below summarise our findings for investment and recurring costs for both fuel options and our chosen locations in both NI and the RoI.

Table 4.16: Investment cost estimates (€m)

Fuel Type	NI Distillate	NI Dual Fuelled	RoI Distillate	RoI Dual Fuelled
EPC costs	€94.500	€95.600	€95.700	€96.900
Site procurement cost	€0.959	€0.950	€0.767	€0.760
Electrical Connection costs	€10.529	€10.529	€6.970	€6.970
Water connection costs	€0.490	€0.490	€0.490	€0.490
Gas connection costs	€0.000	€3.620	€0.000	€3.620
Owners contingency	€4.725	€4.780	€4.785	€4.845
Financing costs	€1.890	€1.912	€1.914	€1.938
Interest during construction	€0.849	€0.880	€1.109	€1.153
Construction insurance	€0.851	€0.860	€0.861	€0.872
Initial fuel working capital	€3.639	€3.057	€2.962	€2.488
Other non EPC costs	€8.505	€8.604	€8.613	€8.721
Accession fees	€0.001	€0.001	€0.000	€0.000
Participation fees	€0.003	€0.003	€0.000	€0.000
Total	**€126.940**	**€131.286**	**€124.171**	**€128.757**

[16] http://www.dfpni.gov.uk/lps/index/property_rating/rate-poundages-2015.htm

Table 4.17: Recurring cost estimates (€m)

Fuel Type	NI Distillate	NI Dual Fuelled	RoI Distillate	RoI Dual Fuelled
Market operator charges	€0.009	€0.010	€0.009	€0.010
Electricity transmission charges	€0.808	€0.841	€1.359	€1.416
Gas transportation charges	€0.000	€0.000	€0.000	€0.000
Operation & Maintenance	€1.940	€1.970	€1.940	€1.970
Insurance	€1.512	€1.530	€1.531	€1.550
Business rates	€0.753	€0.784	€1.532	€1.597
Fuel working capital (ongoing)[17]	€0.165	€0.139	€0.137	€0.115
Total	**€5.187**	**€5.273**	**€6.509**	**€6.658**

Initial views

- **Our initial view is that a distillate and dual fuel BNE plant sited in NI is likely to be slightly more expensive than a BNE plant (distillate or dual fuel) sited in the RoI for investment costs, but less expensive for ongoing costs.**
- **To be consistent with regulatory precedent we propose to calculate the full BNE price for the BNE site in NI and RoI.**
- **As in previous years, on the basis of our initial cost analysis, the BNE plant is likely to be distillate fired.**

[17] Similar to the approach taken in previous years we have included an opportunity cost for holding fuel at the plant. This is calculated as the initial cost of the fuel multiplied by the WACC.

5. ECONOMIC AND FINANCIAL PARAMETERS

This section outlines our consideration of the economic and financial parameters applying to the BNE plant. It follows the format and approach CEPA used in respect of the BNE calculation for the 2010, 2011, 2012 and 2013 trading years. Analysis is summarised here and more detailed supporting information is provided in Annex B.

5.1. Approach

CEPA's approach to deriving the appropriate Weighted Average Cost of Capital (WACC) for the investment in the BNE plant is broadly unchanged from the 2010, 2011, 2012 and 2013 calculations. Within that approach, all parameters have been re-considered in light of new data which has become available since the last BNE decision.

Although a broad range of academic and market evidence exists on the cost of capital for utilities, both in RoI and the UK, the SEM Committee continues to face a difficult task in determining a forward-looking estimate of the cost of capital for the BNE given the limited precedent of regulators setting a WACC for a generator subject to competitive and market constraints. In the RoI, this task is made even harder by volatility in Eurozone financial markets.

In order to address these factors, we continue to make use of traditional finance theory and cross check this against market evidence.

5.1.1. Building blocks of a BNE cost of capital

In line with the majority of regulatory agencies in the RoI and the UK, the approach we adopt in this report is a building-block approach to calculating the WACC. This involves an estimation of the appropriate gearing (measured as net debt: net debt plus equity); cost of debt; cost of equity; and an allowance for the taxation costs of a BNE peaking plant.

An allowance needs to be made for corporation tax payments for the BNE project. This can be done either through a pre-tax WACC or through a post-tax WACC with a separate tax allowance. For the purposes of a notional BNE investment, applying a pre-tax WACC is considered more practical and is in line with previous RA decisions.

We also use a real WACC rather than a nominal WACC as the prices used in the BNE computation are real prices.

5.1.2. BNE peaking plant investment

The RA's are seeking to estimate the cost of capital associated with a BNE peaking plant entering the SEM in the calendar year 2016. This requires assumptions on the nature of the BNE investment, in terms of the profile of the hypothetical BNE investor, including its credit rating, and the financing structure adopted by that investor. Our key assumptions for assessing the cost of capital for the BNE peaking plant are similar to our assumptions from our previous report, and are summarised in the Text Box 5.1 below.

Text Box 5.1: BNE 2016: peaking plan investment assumptions

- **Type of investor -** we assume that the BNE investor is likely to be an integrated utility seeking to raise funding at the corporate level.
- **Plant life –** in line with the 2010 and 2011 BNE calculation the economic life of the project has been taken as 20 years.
- **Financing structure –** we assume that an efficiently financed peaking plant would broadly seek to match the maturity of its debt profile to the anticipated project life of 20 years. Thus we assume an average tenor of 10 years on the new debt.
- **Financing structure -** we also assume that the investor would seek to maximise the debt/equity ratio. For this year's calculation we assume a gearing ratio of 60%.
- **Credit quality –** we assume that a BNE investor has an investment grade credit rating in the range BBB to A. In our analysis of market data, we have employed data for BBB grade debt, which is a more conservative assumption.
- **Investment type -** our assumption is also that the BNE is a green-field investment with no existing assets and associated financing costs. This means that the cost of capital for the BNE is purely a forward-looking estimate for an efficiently operated and financed peaking plant.

As noted above, the assumption that the investor is an integrated utility is important to understanding the method by which finance would be raised for this project. This is supported by market developments. In the Irish market, Endesa sold their generation assets in operation or for construction to SSE in 2012. This included two 104MW peaking plants, a 460MW CCGT under construction at Great Island and a proposed 450MW plant at Tarbert. SSE hold c.13% of generation assets in the SEM. This is slightly below AES Corporation, who own Premier Power Limited, who hold 18% of generation capacity in the SEM.

Centrica have recently bought Bord Gais' generation assets, including the 445MW Whitegate power station. Energia Generation, within the Viridian Group, has two gas fired generation plants totalling 747MW at Huntstown, whilst ESB has also commissioned plants, for example the Aghada Gas-Fired Power Plant, hiring Alstom to install this. We believe that this supports the assumption of an integrated utility and the use of corporate financing in supporting the investment in the BNE plant.

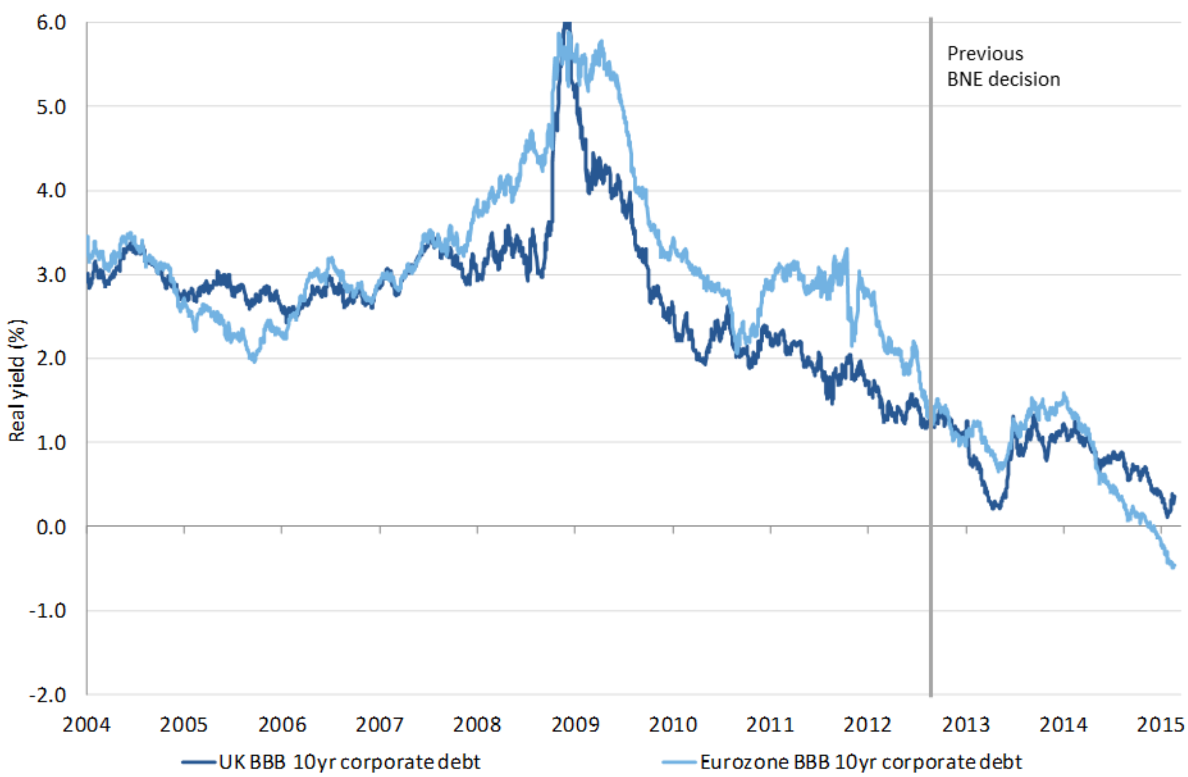
5.2. Estimate of BNE cost of capital

In Annex B, we provide a detailed discussion on how we have arrived at ranges for the cost of capital parameters which would apply to the BNE plant entering the SEM in 2016. This includes discussion of financial market evidence, regulatory precedent on the cost of capital and our views of the appropriate levels for the BNE cost of debt and cost of equity. In this subsection we summarise our initial range for the BNE WACC parameters.

We note that both the regulatory and financial market context are very important for this year's BNE calculation.

As illustrated in Figure 5.1 below, there has been steep fall in the corporate cost of debt in the capital markets[18], in *both* the UK and the Eurozone since the previous 2013 BNE calculation. At a Eurozone level, for example, corporate debt yields have fallen into negative territory in real terms even for BBB rate debt.

Figure 5.1: Corporate cost of debt in UK and Eurozone



Source: CEPA analysis based on Bloomberg data

A BNE investor (either in RoI or NI) would be expected to benefit from the low cost of raising debt for investment in the current market.

[18] We have observed similar trends in the UK credit (bank) market.

The yield on government bonds (a proxy for the risk-free rate) in the UK, Ireland and other Eurozone countries, such as Germany, has also fallen since 2013. This is particularly the case in the RoI, where the large differential observed between the yield on Ireland and German government debt in recent years has for the most part disappeared. Yields on both Irish and UK government gilts are currently at historical lows.

There has also been a range of new regulatory evidence published on the cost of capital as part of the Competition and Markets Authority's (CMA's) determination on the Northern Ireland Electricity (NIE) price control review and the CMA's ongoing investigation into the energy market in Great Britain (GB).

As part of the latter investigation, the CMA has recently released a series of working papers, including on the profitability of GB electricity generation assets and the cost of capital of energy businesses operating in generation and retail supply elements of the value chain and businesses that are vertically integrated.

The CMA has published estimates for the *nominal* cost of capital for the 2007-2014 period, the parameters of which are summarised in the table below. This corresponds to what the CMA consider an investor could reasonably have *expected* for the cost of capital when making an investment decision during this period.

Table 5.1: Nominal cost of Capital Parameter Range for energy companies 2007-14

	Vertically Integrated		Generation		Retail Supply	
	Low	High	Low	High	Low	High
Real risk-free rate	1.0%	1.5%	1.0%	1.5%	1.0%	1.5%
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%	-	-
Equity Risk Premium	4.0%	5.0%	4.0%	5.0%	4.0%	5.0%
Asset Beta	0.5	0.6	0.5	0.6	0.7	0.8
Taxation	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
Pre-tax CoE[1] (nominal)	9.6%	10.3%	9.6%	10.3%	9.3%	11.0%
Gearing	20%	40%	20%	40%	0%	0%
Nominal pre-tax WACC	7.7%	9.5%	7.9%	9.5%	9.3%	11.0%

Note 1 – Cost of equity

Source: CMA (adapted by CEPA)

Although the CMA's analysis should not be compared directly with current market evidence (the UK corporation tax rate, for example, has fallen significantly in recent years) we note the following for the BNE calculation:

- the CMA adopt a lower assumption on gearing compared to recent BNE determinations which used a 60 per cent gearing assumption;
- the CMA propose a range for the generation asset beta (to reflect its view of the systematic risk of generation in the GB market) of 0.5 to 0.6, broadly consistent with the beta assumption used in recent BNE calculations[19]; and
- overall the real pre-tax WACC for generation (albeit with different individual parameter assumptions applied) is in a similar range to that applied by the SEM Committee for recent BNE determinations, where the peaking plant was assumed to be located in NI and, therefore, the UK.

The evidence from the CMA investigation and current evidence in financial markets, both in the UK and the Eurozone, has influenced the initial cost of capital ranges we have developed for this year's BNE plant. In general, this has led to a fall in the WACC parameters relative to the 2013 determination, as detailed below.

5.2.1. Gearing

As we have noted in our previous BNE reports, identifying an appropriate gearing assumption for the BNE is inevitably a judgment as the plant is a notional investment in the SEM.

For regulatory stability purposes and based on guidance from the SEM Committee, we have retained a gearing assumption of 60% for the BNE. We welcome further evidence from stakeholders' on whether this assumption is appropriate.

5.2.2. Cost of debt

We estimate an all-in cost of debt for both NI and RoI, without decomposing this into a risk-free rate and debt premium.

Our estimate of the appropriate range for the BNE cost of debt is 0.75%-2.25% in NI. This is a reduction in the range that was used in the 2013 BNE determination.

Assessing the cost of debt for the BNE in the RoI is made more difficult by the difference between spot rates and historic average yields for benchmark indices and utility bonds. We

[19] Recent BNE calculations have applied an equity beta assumption in the range 1.2 to 1.3. If a debt beta of 0.1 is assumed, together with a notional gearing assumption of 60%, this implies an asset beta range of 0.54 to 0.58.

propose that the appropriate cost of debt to allow a BNE peaking plant investment in the RoI for 2016 lies within the range 1.00% - 3.00%.

The top end of the range accounts for the ongoing uncertainty in Eurozone financial markets and accounts for the risk of a return to more challenging financing conditions in the RoI. The bottom end of the range reflects shorter term trends on corporate borrowing costs (although above spot rates for mid-investment grade corporate debt).

5.2.3. Cost of equity

We have again deployed the Capital Asset Pricing Model (CAPM) as the primary tool for estimating the cost of equity, with a cross-check to recent regulatory precedent.

Our judgement is that the appropriate range for the pre-tax cost of equity for the BNE peaking plant is 7.66% - 8.94% in the RoI and 8.13% - 9.69% in NI.

5.2.4. Taxation

We have again calculated the WACC for the BNE on a real pre-tax basis using an assumed statutory corporation tax rate for the jurisdiction in which the BNE is located.

5.2.5. WACC

Our judgement of the appropriate range for the real pre-tax WACC for the BNE peaking plant is thus 3.66% - 5.38% in the RoI and 3.70% - 5.23% in NI.

Initial views

- **We have reviewed market evidence and regulatory precedent on notional gearing. For regulatory stability purposes, the estimate of the gearing for the BNE remains at 60%.**
- **We continue to assume that the plant life for the BNE will be 20 years and that the BNE investor would target an average debt life of 10 years.**
- **We also continue to conservatively assume that whilst the investor will be 'investment grade', the debt raised will be based on BBB grade costs.**
- **Our estimate of the appropriate range for the BNE cost of debt is 1.00% - 3.00% in the RoI and 0.75% - 2.25% in NI.**
- **Our judgement of the appropriate range for the pre-tax cost of equity in the RoI and NI is 7.66% - 8.94% and 8.13% -9.69% respectively.**
- **We have calculated the WACC for the BNE on a real pre-tax basis using an assumed statutory corporation tax rate for the jurisdiction in which the BNE is located.**
- **This points to a range for the assumed real pre-tax WACC of 3.66% - 5.38% in the RoI and a range of 3.70% - 5.23% in the UK.**

6. INFRA-MARGINAL RENT AND ANCILLARY SERVICE REVENUES

We now proceed to calculate the infra marginal rent and Ancillary Services (AS) revenues earned by the selected peaker. Our approach replicates the process used in the previous BNE report: that is to subtract revenues accruing to the BNE peaker as a result of activity in the energy market and AS revenues.

6.1. Infra-marginal rent

The RAs have adopted the formulae set out in the MTR decision paper to determine the Infra-Marginal rent which will be earned by the BNE plant. The RAs have identified that €6.10/kW infra-marginal rent would be earned by the BNE peaking plant.

6.2. Ancillary Services

A BNE plant entering the SEM in 2016 would be expected to earn AS revenues under the existing harmonised all-island arrangements for AS introduced in 2010.

Estimates of the BNE's AS revenues are based on information provided by the TSOs who reviewed the unit for the 2012 BNE calculation decision paper.

We have updated the AS income and penalties to account for the change in the average lifetime output of the 2016 BNE plant and using the harmonised AS rates and other system charges proposed for the tariff year 1 October 2015 – 20 September 2016.

The proposed parameters adopted in the BNE AS revenue calculation are as follows:

Table 6.1: Ancillary service values for use in the BNE calculation for 2016

Parameter	Value	Unit	Source
POR	21.2	MW	SONI/EirGrid minimum functional spec
SOR	35.4	MW	SONI/EirGrid minimum functional spec
TOR1	35.4	MW	SONI/EirGrid minimum functional spec
TOR2	35.4	MW	SONI/EirGrid minimum functional spec
RR	195.7	MW	SONI/EirGrid minimum functional spec
Min MW for POR	19.7	MW	SONI/EirGrid minimum functional spec
Min MW for SOR	19.7	MW	SONI/EirGrid minimum functional spec
Min MW for TOR1	19.7	MW	SONI/EirGrid minimum functional spec
Min MW for TOR2	19.7	MW	SONI/EirGrid minimum functional spec
Min MW for RR	0.0	MW	SONI/EirGrid minimum functional spec

Parameter	Value	Unit	Source
Reactive Power Leading	64.6	MVar	SONI/EirGrid minimum functional spec
Reactive Power Lagging	147.4	MVar	SONI/EirGrid minimum functional spec

Using these values and the RA assumption of 60% load factor when running gives the following output for AS revenues:

Table 6.2: AS for 2016 BNE

Parameter	Not running [€/TP]	Running [€/TP]
POR		25.02
SOR		40.18
TOR1		33.10
TOR2		16.46
RR		7.83
Reactive Power Leading	52.84	8.40
Reactive Power Lagging		19.16
Total	**52.84**	**150.15**

The potential AS income using the RA assumption of 95% availability and 2% run hours is therefore:

$$= (52.84 \times 0.95 \times 48 \times 365) + (150.15 * 0.02 * 48 * 365) = € 932{,}082$$

In the 2012 BNE decision paper, the RAs also clarified the applied penalties to cover the scenario of one trip and associated Short Notice Declaration (SND) events. A 195.7MW direct trip and a 195.7MW SND at zero notice time gives:

- Trip charge = €10,624
- SND (2014/15 rates) = €13,973

This gives a value of AS revenues that the BNE peaking plant for 2016 would achieve under the current harmonised AS framework of € 907,485.

7. Initial view of the BNE price

Based on the discussions in the previous sections of this document, we now provide our initial estimate of the fixed costs of a distillate fired BNE peaking plant located at a notional site in both the RoI and NI.

7.1. Additional modelling assumptions

In order to increase transparency, the other modelling assumptions we have used and brief justifications for those assumptions are given below.

Table 7.1: Justification for key modelling assumptions

Assumption	Justification
Euro to Sterling exchange rate is 1.3863 Euros to the pound.	Spot rate at time of developing document. Spot rate viewed as best indicator of future rate.
Midpoints of ranges for cost of capital have been used.	CEPA/Ramboll have recommended ranges, the midpoint is used for ease but does not necessarily represent our view on the point estimate of the cost of capital.
Residual value of land and fuel included by present valuing of end term values	These items will have a real value that can be realised in the market
No residual value for plant	Plant life is assumed to be 20 years
Interest During Construction (IDC)	Based on steady drawdown of loan in proportion to gearing
Initial Working Capital	Initial fuel charge plus two month's payables
Owner's contingency	Included
Capacity MW	On a sent out basis allowing for degradation

7.2. Results

Table 7.2 overleaf brings together the issues discussed in the previous sections to provide our initial assessment of the fixed costs of locating a BNE plant in either the RoI or NI. On the basis of the analysis set out, the costs would be:

- In NI €**76.24/kW/yr**.
- In the RoI €**82.31/kW/yr**.

This is before deductions for infra marginal rent and ancillary service revenues.

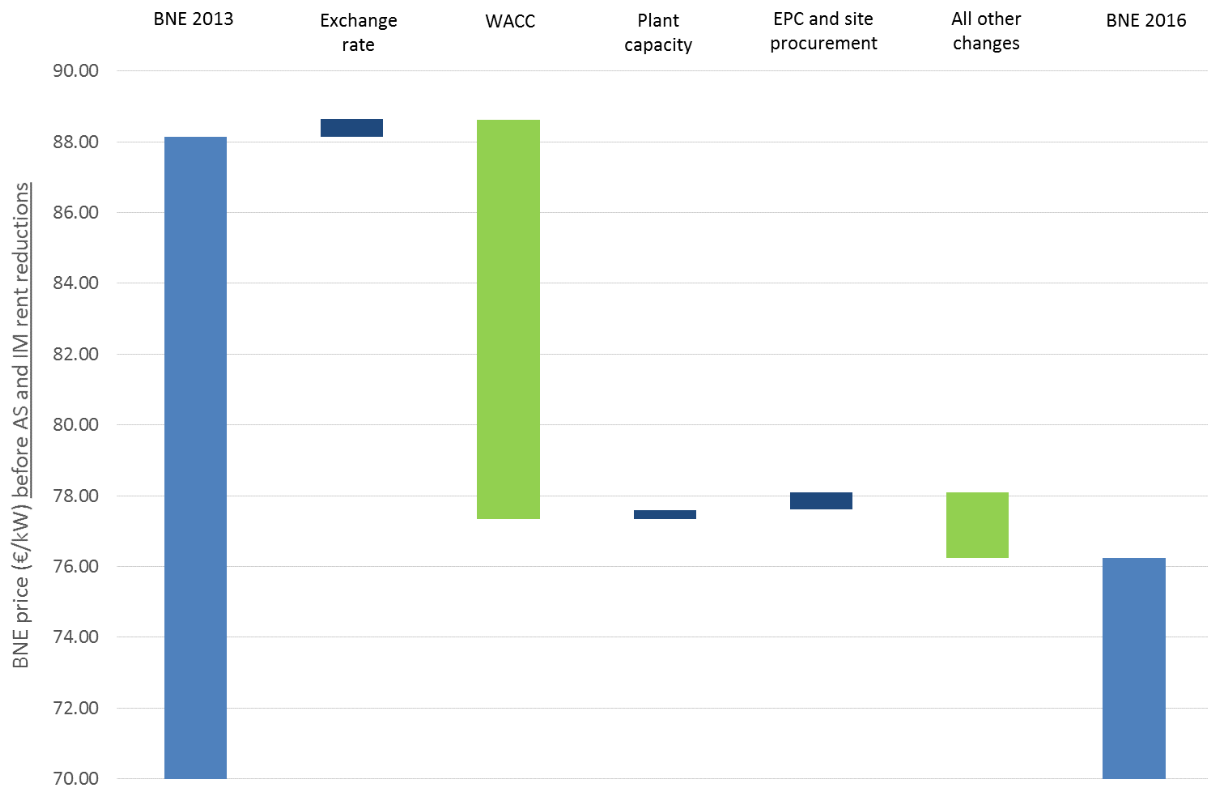
Table 7.2: Summary assessment of the costs of a distillate fired BNE plant in the RoI or NI

Line Item	Unit	NI	RoI
Total investment costs	€ million	123.30	121.21
Land and Fuel Residual Value	€ million	1.92	1.54
Initial Working Capital	€ million	5.71	5.02
Total Annual Costs	€ million	14.92	16.11
Plant Size	MW	195.7	195.7
Pre Tax WACC	%	4.46%	4.52%
Plant Life	Years	20	20
Estimated BNE cost (before reductions)	€/kW	**76.24**	**82.31**
Inframarginal Rent	€/kW	6.10	
Ancillary Service revenues	€ 000/annum	4.64	
Estimated BNE cost	€/kW	**65.50**	

Initial views

- **We therefore consider, albeit on the basis of initial analysis, that the plant should be distillate fired and located in NI.**
- **The estimated cost of €65.50/kW is below the €76.34 allowed for 2013. The figure below illustrates which components of the BNE price (before AS and IMR reductions) have caused the change since the 2013 calculation.**

Figure 7.1: Change in BNE price – 2013 to 2016 – before infra-marginal rent and AS revenue reductions



Source: CEPA / Ramboll analysis

Notes: green bars show a reduction in price whilst the dark blue bar shows an increase in price. Electrical connection costs are included in EPC and site procurement costs

ANNEX A CEPA/ RAMBOLL LONG-LIST OF PLANT

Model	Commercially available?	Proven track record?	Start time<20 minutes	Dual fuel?	Selected	Shortlisted?
Alstom GT11N2	Yes	Yes	Yes	Yes	Yes	No
Alstom GT13E2	Yes	Yes	Yes	Yes	Yes	Yes
Ansaldo AE64.3A	Yes	Yes	Yes	Yes	Yes	No
Ansaldo AE94.2	Yes	Yes	Yes	Yes	Yes	Yes
Ansaldo AE94.3A	Yes	Yes	No	N/A	No	No
GE 6B.03	Yes	Yes	Yes	Yes	Yes	No
GE 6F.01	Yes	Yes	Yes	Yes	Yes	No
GE 6F.03	Yes	Yes	No	N/A	No	No
GE 9231C	No	N/A	N/A	N/A	No	No
GE 9E.03	Yes	Yes	Yes	Yes	Yes	Yes
GE 9F.03	Yes	Yes	No	N/A	No	No
GE LM6000PC Sprint	Yes	Yes	Yes	Yes	Yes	No
GE LM6000PG Sprint	Yes	Yes	Yes	Yes	Yes	No
GE LMS100 PA	Yes	Yes	Yes	Yes	Yes	No
P&W FT4000 Swift Pac 120	Yes	No	N/A	N/A	No	No
P&W FT8 Swift Pac 60	Yes	Yes	Yes	Yes	Yes	No
RR RB211-H63	No	N/A	N/A	N/A	No	No
RR Trent 60 Dry	Yes	Yes	Yes	No	No	No
RR Trent 60 WLE	Yes	Yes	Yes	Yes	Yes	No
Siemens SGT-750	Yes	Yes	Yes	No	No	No
Siemens SGT-800	Yes	Yes	Yes	Yes	Yes	No
Siemens SGT-1000F	No	N/A	N/A	N/A	No	No
Siemens SGT5-2000E	Yes	Yes	Yes	Yes	Yes	Yes
Siemens SGT5-3000E	No	N/A	N/A	N/A	No	No
Siemens SGT5-3000F	Yes	Yes	No	N/A	No	No

ANNEX B COST OF CAPITAL FOR A BNE PLANT

B.1. Overview

This annex sets out our analysis of the weighted average cost of capital (WACC) for a BNE peaking plant seeking to enter the SEM in the calendar year 2016. It begins with a review of the previous determination on the BNE cost of capital, an overview of the proposed approach and then our view on the individual parameters that make up the cost of capital range set out.

B.2. Previous BNE determination

Table B1 below outlines the cost of capital parameters that were adopted in the decision paper for the Best New Entrant Peaking Plant and Capacity Requirement for 2013.

Table B1: Cost of Capital Parameter Ranges for BNE 2013 (real)

	Republic of Ireland		Northern Ireland (UK)	
	Low	High	Low	High
Risk-free rate	3.50%	5.50%	1.50%	2.00%
Debt premium	2.25%	2.75%	2.25%	2.75%
Cost of Debt	5.75%	8.25%	3.75%	4.75%
Equity Risk Premium	4.50%	5.00%	4.50%	5.00%
Equity Beta	1.20	1.30	1.20	1.30
Post-tax Cost of Equity	8.90%	12.00%	6.90%	8.50%
Taxation	12.50%	12.50%	24.0%	24.0%
Pre-tax Cost of Equity	10.17%	13.71%	9.08%	11.18%
Gearing	60.00%	60.00%	60.00%	60.00%
Pre-tax WACC	7.52%	10.44%	5.88%	7.32%

The BNE 2013 was located in NI, and therefore the cost of capital range for NI was used and a mid-point figure adopted (6.60% as a pre-tax WACC).

B.3. Approach and assumptions

The nature of our analysis remains consistent with previous years' methodologies – we adopt a building block approach to setting the cost of capital, in line with the approach used by the Regulatory Authorities (RAs). We have considered evidence on the cost of capital up to the 2017 trading year, after which we understand the I-SEM must be implemented by and the calculation is expected to no longer be used in setting the CPM.

There is limited precedent of utility regulators setting a cost of capital for an electricity generator subject to competitive and market constraints. Regulated networks are not direct comparisons, as these will typically be lower risk than the BNE and will have embedded debt, whereas we assume that the notional BNE will be financed by entirely new debt and equity taken out in the period considered.

The cost of capital we estimate is in pre-tax real terms. The use of a pre-tax WACC to allow for taxation costs is considered more practical and consistent with previous RA decisions than for example modelling taxation costs separately, while the BNE prices set out are in real terms and thus it makes sense to set a real cost of capital. The cost of capital is a forward looking one based on the assumptions set out in Table B.2.

Table B.2: Peaking Plant Investment Assumptions

Parameter	Assumption
Type of investor	Integrated utility seeking to raise funding at the corporate level
Plant Life	Economic life of the project is 20 years
Debt profile	Match maturity to asset life; average tenor of 10 years for new debt
Financing structure	Maximise D/E ratio based on risk
Credit quality	Investment grade quality – BBB/A. Assume BBB for this analysis
Investment type	Green-field with no existing assets and associated financing costs

B.3.1. Cost of Debt approach

An efficiently financed BNE peaking plant will look to adopt an 'optimal' debt structure that broadly matches the useful life of its assets, whilst minimising actual debt financing costs and mitigating various risks such as interest rate risk and refinancing risk.

We have assumed that the plant life for the BNE will be 20 years (as discussed in Section 5), an unchanged assumption from previous BNE trading years. The broad expectation continues to be that the BNE would seek to match the maturity of its debt profile to the average useful life of its assets and would spread its debt maturity profile across a number of tenors – averaging around a 10 year maturity.

The cost of debt for the BNE peaking plant is equivalent to a cost of new debt under our assumptions. We assume that the BNE issues debt with an average tenor of ten years to reduce refinancing risk. We calculate an all-in cost of debt, consistent with the approach applied by the CMA in regulatory determination referrals, rather than decompose the cost of debt into risk-free rate and debt premium constituent parts.

B.3.2. Cost of Equity approach

We have employed the capital asset pricing model (CAPM) as the primary tool for estimating a notional BNE peaking plant's cost of equity. The CAPM defined cost of equity equation is presented below:

$$CoE = r_f + \beta_{Equity}(ERP)$$

where $CoE =$ cost of equity

r_f = risk-free rate

$ERP =$ equity risk premium for the market portfolio

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

The risk-free rate and equity risk premium (ERP) are economy-wide variables, whilst the equity beta is by definition company-specific. The approach we take mirrors the methodology of the CMA, in deducting a risk-free rate from a total market return to establish an ERP.

We calculate a medium to long-run risk-free rate estimate, and update the estimates of the ERP and equity beta from our previous analysis based on the latest available information.

B.4. Regional and country premia

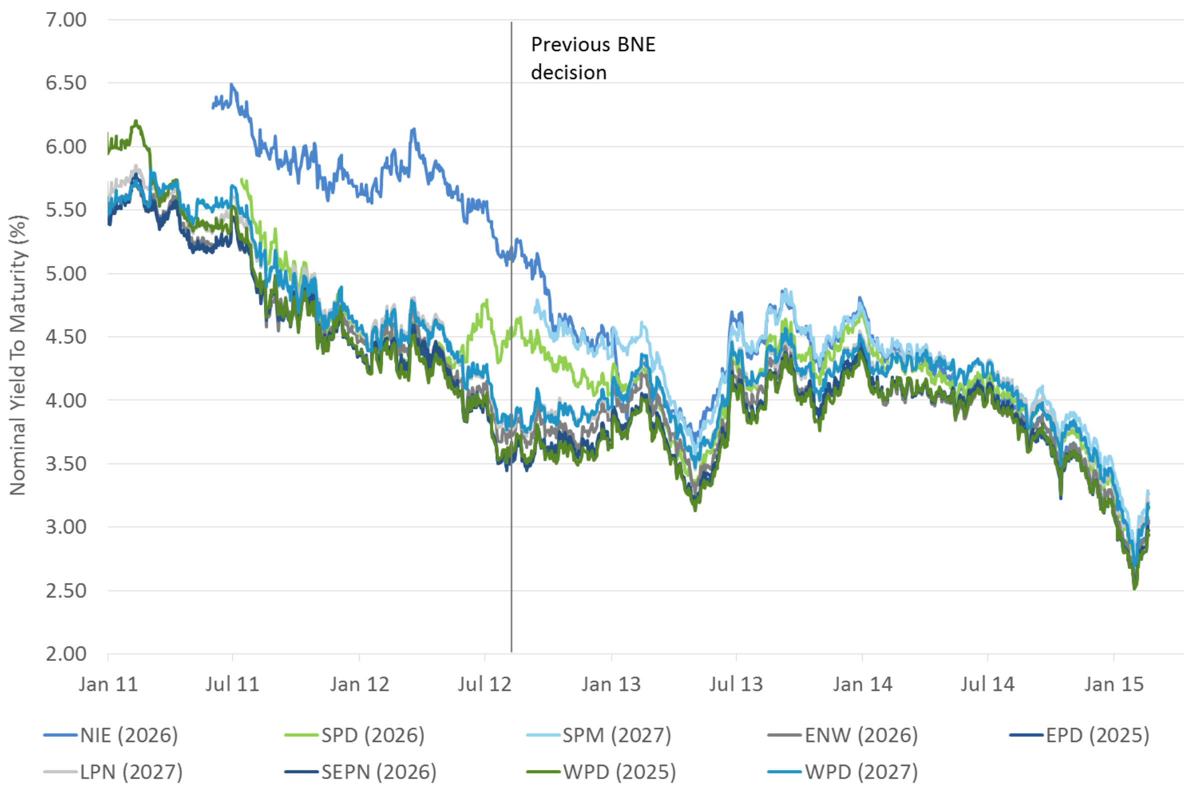
When considering market evidence, we have looked at whether a regional or company premium should apply when considering UK data for NI, and Eurozone data for the RoI.

B.4.1. Northern Ireland premium relative to UK

An issue considered by the RAs for the BNE 2013 and by the CMA for the NIE T&D RP5 determination was the existence of a premium for NI relative to the UK as a whole. In the BNE 2013 report, an additional 50bps on the debt premium was included, with no explicit premium on the cost of equity. The CMA did not include a NI premium on the cost of equity and any premium on the cost of debt would be implicit, as they use the cost of debt for NIE itself rather than use of a benchmark. As the BNE is a notional entity, we cannot use actual cost of debt.

In terms of the analysis used by the CMA, NIE was analysed against regulated UK electricity distribution companies' bonds that had similar credit ratings and time to maturity. A differential of 150bps was observed in April 2012, but since early 2013 this differential has been no more than 20bps. The bonds are not perfect matches, so there will be small differences in yield due to differing term premia and a notch lower credit rating for two of our comparator bonds (SPD Finance and SP Manweb) relative to NIE and the other bonds listed.

Figure B.1: NIE 2026 bond and comparable UK electricity distribution company bonds[20]



Source: Bloomberg

This analysis does not indicate that an explicit premium is required for NI relative to the UK. It should be noted that NIE falls under ESB ownership (the CMA state that they cannot be certain what effect this has), itself being state owned.

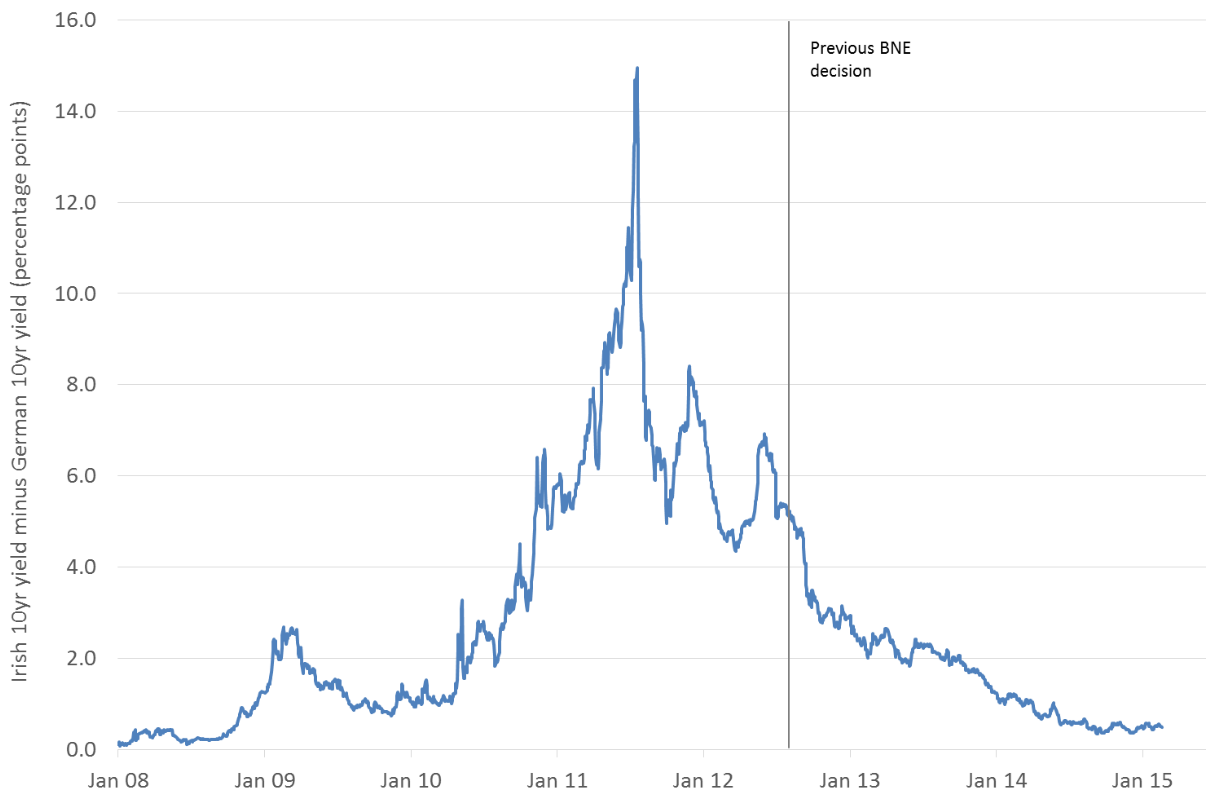
B.4.2. RoI premium relative to Eurozone

In setting the cost of capital and capacity payment values for previous BNE decisions, a substantial premium between German (as a proxy for the Eurozone) and Irish sovereign debt

[20] NIE = NIE Finance (BBB+), SPD = SPD Finance (BBB), SPM = SP Manweb (BBB), ENW = Electricity North West (BBB+), EPD = Eastern Power Networks (BBB+), LPN = London Power Networks (BBB+), SEPN = South Eastern Power Networks (BBB+), WPD = Western Power Distribution (BBB+).

yields was observed. Consequently a RoI Country Risk Premium (CRP) was an option for capturing this risk differential. Over the last year, this differential has largely eroded, although German yields remain slightly below the Irish equivalent yields. A comparison of ten year sovereign debt is illustrated in Figure B.2 below.

Figure B.2: Irish 10 year gilt yield minus German 10 year gilt yield



Source: Bloomberg, ECB

B.5. WACC parameters for Northern Ireland

In this section we look at the five building block components for the cost of capital for Northern Ireland. These five components are:

1. Notional gearing
2. Cost of Debt
3. Risk-free rate
4. Equity Risk Premium
5. Equity Beta

For each of these components, we break our analysis down into four categories:

A. Market Evidence
B. Regulatory Precedent
C. Commentary
D. CEPA Assessment

N Ireland (UK)	GEARING	1. Notional gearing	A. Market evidence

The CMA have published analysis in a working paper on the cost of capital as part of its GB energy market investigation, looking at large UK energy companies, generation firms and retail suppliers. We present this information in Table B.3 below, presenting 2011-2013 gearing levels, and an average from 2006-2013[21].

Table B.3: Gearing for listed utility comparators (%)

Company	2011	2012	2013	2006-2013
Centrica	19.5	20.2	22.9	15.4
SSE	30.3	32.5	27.9	27.0
EDF	51.5	64.5	45.1	37.2
E.ON	45.8	46.9	43.2	36.0
Iberdrola	49.2	51.5	48.6	43.7
RWE npower	52.0	49.9	50.3	29.6
GDF Suez	55.7	61.1	47.8	39.1
Drax plc	0.0	0.0	0.0	4.8

[21] https://assets.digital.cabinet-office.gov.uk/media/54edfe9340f0b6142a000001/Cost_of_capital.pdf

Company	2011	2012	2013	2006-2013
AES Corp	71.6	72.6	67.9	66.8
AEP Corp	46.9	46.7	45.0	47.8
Good Energy Group	-	0.0	18.0	9.0
Telecom Plus	4.2	0.0	0.0	0.5
Just Energy	19.3	27.4	49.2	14.3

This indicates levels of gearing which have been around 30-40% for vertically integrated companies, a wide range for generation firms and then low levels for retail suppliers. There has been an increase in gearing over the 2006-13 period for the majority of firms.

Table 7.4 below shows corporate leverage levels for a range of utility companies in the UK, that have not been included in the CMA table above. This includes Alkane, an independent power generator, the others may be termed "network" utilities.

Table 7.4: Gearing for listed utility comparators

Company	1yr average	3yr average	5yr average
National Grid	40.1%	41.8%	46.5%
United Utilities	50.4%	52.8%	54.8%
Severn Trent	48.8%	49.9%	51.8%
Alkane	22.2%	20.9%	20.5%

Note: gearing is based on net debt/ (net debt + market capitalisation). Data up to 1 March 2015.

These gearing figures are typically below those assumed in regulatory precedent (for regulated network utilities) and are significantly below those typically observed in many Project Finance-type infrastructure projects.

N Ireland (UK)	GEARING	1. Notional gearing	B. Regulatory precedent

Table B.5 below shows notional gearing assumptions used for recent UK regulatory determinations on the cost of capital.

Table B.5: Regulatory determinations on gearing (UK)

Regulator	Decision	Gearing (%)
Ofwat	PR14 (2015-2020)	62.5%
Ofgem	RIIO ED1 (2015-2023)	65.0%
Ofcom	Fixed Access - Openreach	32.0%
Ofcom	Fixed Access – BT Group	32.0%
Ofcom	Fixed Access – Rest of BT	32.0%

Regulator	Decision	Gearing (%)
CMA	NIE T&D (2012-2017)	45.0%
CAA	Q6 – Heathrow (2014-2019)	60.0%
CAA	Q6 – Gatwick (2014-2019)	55.0%
ORR	PR13 (2014-2019)	62.5%
Ofgem	RIIO GD1 (2013-2021)	65.0%
Ofgem	RIIO T1 – Scottish TOs (2013-2021)	55.0%
Ofgem	RIIO T1 – NGET (2013-2021)	60.0%
Ofgem	RIIO T1 – NGGT (2013-2021)	62.5%
CER/NIAUR	Best New Entrant - NI (2013)	60.0%

N Ireland (UK)	GEARING	1. Notional gearing	C. Commentary

- **CMA analysis:** In their review of the cost of capital for energy firms, as part of their energy market investigation, the CMA point to a gearing level of 20-40% for both vertically integrated energy companies and standalone generators. This is lower than the estimate of 60% gearing used for the BNE 2013.
- **Investor type:** In our assumptions for the BNE (see main report), we set out that we expect the investor to be an integrated utility. Market evidence would indicate lower levels of gearing than the 60% previously assumed for the BNE.
- **Sensitivity of WACC to notional gearing:** when calculated with the CAPM, it should be noted that the cost of capital is not especially sensitive to the level of notional gearing adopted. This is due to the cost of equity increasing with the level of gearing, offsetting the increased weight of the lower cost of debt in the overall cost of capital.
- **Observed gearing levels:** The level of gearing for non-financial corporates in the FTSE100 index is 37%.[22] This level is significantly higher for financial institutions.
- **Movements in the gearing level:** In recent years, there has been an increase in the amount of debt issued by corporates in a low interest environment, although the level of cash reserves have also increased. Net debt has slightly increased in the market as a whole, however not to a dramatic extent.

[22] http://www.economist.com/news/britain/21631139-bank-england-announces-plans-make-banks-safer-never-lever-land

- **Comparison to other assets:** There is a large range of gearing observed for different utility assets. Regulated onshore assets have typically exhibited gearing levels approximate to the notional gearing assumptions assumed in price control determinations which have typically been around 60-65%. However, several regulated water companies have used several more highly geared structures (up to 90%). Project Finance deals and OFTO transactions have gearing ratios of approximately 90%.

N Ireland (UK)	GEARING	1. Notional gearing	D. CEPA Assessment

For regulatory stability purposes and based on guidance from the SEM Committee, we have retained a gearing assumption of 60% for the BNE. We welcome further evidence from stakeholders' on whether this assumption is appropriate.

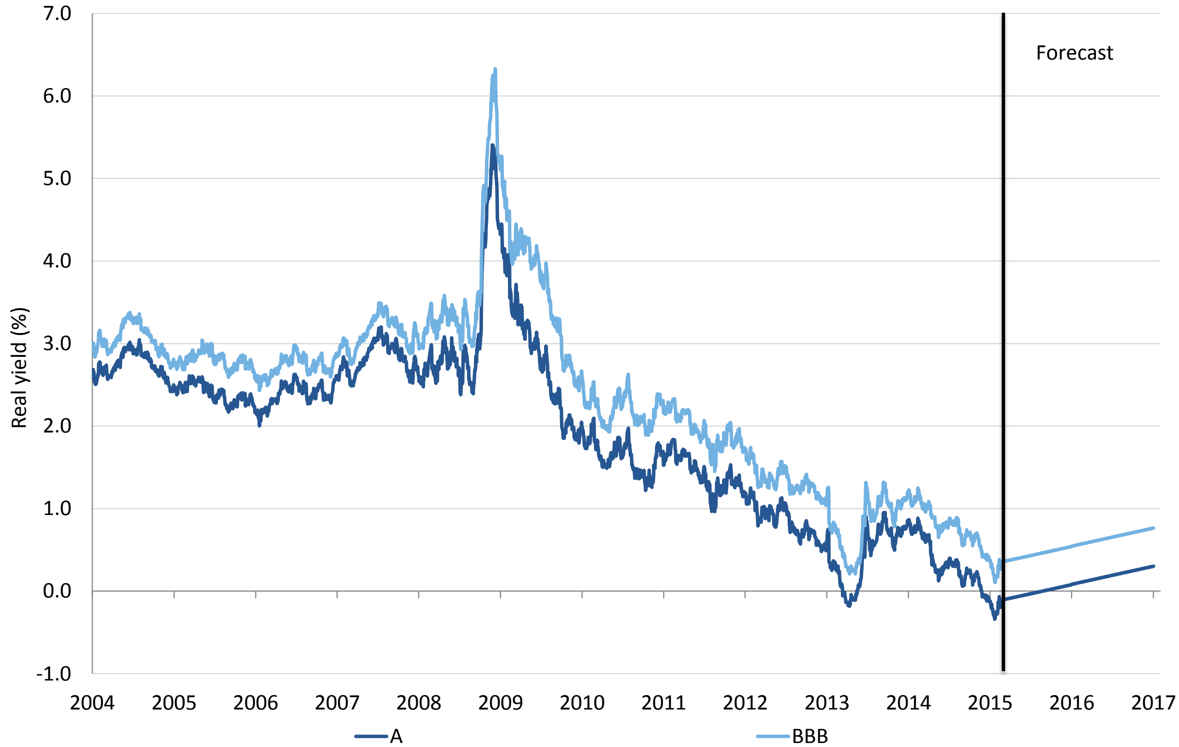
N Ireland (UK)	COST OF DEBT	2. All-in Cost of Debt	A. Market evidence

The CMA in their NIE T&D determination for RP5 do not separate the cost of debt into a risk-free rate and debt premium. The use of a risk-free rate for both the cost of debt and cost of equity can be complicated given the different time periods being considered. For example, one approach would be to assume that the investor issues debt to match the asset life and fixes that cost of debt in the 2016 (or 2017) calendar year. For an equity investor with a 20 year investment horizon, the return will vary over the period. As such, our approach to estimating the cost of equity involves looking at medium to long run market evidence, whilst we assume that the BNE plant would seek to match their debt financing with costs.

All-In Cost of Debt

The figure below shows real yields on UK ten-year corporate debt. We include a forecast through the calendar year 2016. This is based on forecast changes in nominal gilts of ten year maturity, with no change in inflation expectations.

Figure B.3: Real yields on UK corporate debt of ten-year tenor



Source: Bloomberg, Bank of England

Based on this analysis, the forecast real yield for UK corporate BBB rated debt in 2016 will be equal to 0.65% real. For A rated debt in 2016, this is equal to 0.19%. This is prior to the application of any fees.

An alternative source of evidence is the iBoxx indices. Ofgem use the iBoxx ten-years plus corporate debt indices for cost of debt indexation under their RIIO price controls. With an upwards sloping yield curve, the longer tenor of debt gives higher yields. We forecast future rates using UK nominal gilt changes, as per our approach with the Bloomberg indices.

Figure B.4: Real yields on UK corporate debt of ten-years plus tenor

Source: Markit iBoxx, Bank of England, Bloomberg

For the calendar year 2016, a real yield of 0.99% is forecast for A and BBB rated corporate debt of ten year plus maturity. We look at utility bond yields to cross-check our findings above.

UK utility bonds

The table below summarises market data for a selection of bonds issued by the utilities in the UK. We have presented data for both energy companies and water companies.

Table B6: Utility bond data in UK[23]

Company	Maturity	Amount	Credit rating	Yield to maturity today (nominal)	Spread to gilt today
NIE Finance	06/2026	£400m	BBB+	3.01%	103bps
Energy companies					
WWU	12/2023	£250m	A-	2.67%	120bps
WPD	10/2024	£400m	BBB	2.82%	112bps
Southern GN	02/2025	£350m	BBB	2.68%	91bps

[23] Data as of 20 February 2015

Company	Maturity	Amount	Credit rating	Yield to maturity today (nominal)	Spread to gilt today
National Grid Elec	06/2027	£525m	A-	2.78%	80bps
Centrica	03/2029	£750m	A-	3.33%	134bps
WWU	03/2030	£300m	A-	3.22%	107bps
WPD	04/2032	£800m	BBB	3.40%	115bps
NPG	07/2032	£150m	A-	3.34%	109bps
NGN	03/2040	£200m	BBB+	3.64%	122bps
Centrica	09/2044	£550m	A-	3.86%	138bps
Water companies					
Kelda Water	02/2020	£200m	BB-	4.62%	331bps
Wessex Water	09/2021	£300m	BBB+	2.31%	90bps
United Utilities	03/2022	£375m	BBB+	2.44%	121bps
Thames Water	06/2025	£500m	A-	2.79%	102bps
Anglian Water	02/2026	£200m	BBB	3.38%	160bps
Anglian Water	10/2027	£250m	A-	3.03%	105bps
Affinity Water	03/2036	£250m	A-	3.43%	104bps

Source: Bloomberg

The data on utility bond issuance is in line with the broader market data observed earlier. If the debt was not investment grade, a higher cost of debt would be required to account for the greater perceived risk.

N Ireland (UK)	COST OF DEBT	2. All-in Cost of Debt	B. Regulatory precedent

In estimating the cost of capital for the BNE, it is important that our approach is consistent with the best practice approach taken by other regulators. This does not mean that the cost of capital parameter values should necessarily be the similar, but the relationship between market evidence and how regulatory bodies have estimate the allowed cost of capital must be considered. The cost of new debt is the relevant comparator for this analysis, given that we have assumed that the BNE peaking plant will have no embedded debt.

The table below summarises recent determinations in the UK on the cost of debt.

Table B7 : Regulatory determinations on the cost of debt in the UK

Regulator	Decision	Risk-free rate	Cost of debt (all)	Cost of new debt
United Kingdom				

Regulator	Decision	Risk-free rate	Cost of debt (all)	Cost of new debt
Ofwat	PR14 (2015-2020)	1.25%	2.59%	2.10%
Ofgem	RIIO ED1 (2015-2023)	1.00%*	Index	Index
Ofcom	Fixed Access - Openreach	1.30%	2.30%	n/a
Ofcom	Fixed Access – BT Group	1.30%	2.55%	n/a
Ofcom	Fixed Access – Rest of BT	1.30%	2.80%	n/a
CMA	NIE T&D (2012-2017)	1.25%	3.40%	2.14%
CAA	Q6 – Heathrow (2014-2019)	0.50%	3.20%	n/a
CAA	Q6 – Gatwick (2014-2019)	0.50%	3.20%	n/a
ORR	PR13 (2014-2019)	1.75%	3.00%	n/a
Ofgem	RIIO GD1 (2013-2021)	2.00%	Index	Index
Ofgem	RIIO T1 – Scottish TOs (2013-2021)	2.00%	Index	Index
Ofgem	RIIO T1 – NGET (2013-2021)	2.00%	Index	Index
Ofgem	RIIO T1 – NGGT (2013-2021)	2.00%	Index	Index
CER/NIAUR	Best New Entrant - NI (2013)	1.75%	n/a	4.0%%

*Note: * indicates implied figure*

Outside of price control determinations, useful regulatory precedent may be found from electricity interconnection. This project involves a single asset, where the time of construction is known. Ofgem's regulation of interconnectors involves a regulated cap and floor model of revenues. The first interconnector to be regulated under this approach is the Project Nemo interconnector between Belgium and GB.

Ofgem use the floor as a proxy for the cost of debt in the NEMO regulatory model. The iBoxx ten years plus non-financial corporate BBB and A rated debt indices are used, deflated by ten year breakeven inflation. A shorter term average is taken in establishing the cost of debt (twenty working days). The current estimate for this would be 0.90% based on the twenty working days (to 20 February 2015). This indicates that a cost of debt below 1.0% is not inconsistent with all regulatory precedent.

N Ireland (UK)	COST OF DEBT	2. All-in Cost of Debt	C. Commentary

- **Spread calculation over risk-free rate:** UK spreads observed have typically been at 90-150bps above the equivalent gilt. The ten year ILG currently yields -0.73%, so combining these premiums with the risk-free rate would lead to a low real cost of debt.

- **Low real cost of debt:** Ten year tenor non-financial BBB rated debt currently has a yield of c.0.2%. This is at a historically low level and significantly below the cost of debt allowed in regulated sectors such as onshore energy networks.
- **Impact of debt tenor:** The choice of debt tenor matters. Looking at ten year corporate debt (Bloomberg) and ten year plus corporate debt (iBoxx) gives a difference of c.70bps between the two indices for 2016.
- **Utility cost of debt:** Looking at utility bonds with mid investment grade credit quality for 10-15 year debt shows present *nominal* yields at c.2.7-3.4%. Ten year breakeven inflation is currently at 2.7%.
- **Fees:** When considering the cost of debt assumption, we must ensure that this captures the costs incurred. Our market evidence shows the coupon for issuers, but does not include issuance costs. For the CMA NIE determination, total fees of 20bps were included on the cost of new debt.
- **Generation credit rating:** Analysis from the CMA indicates that a stand-alone generation plant would sit just below investment grade in terms of credit ratings. As the investor is assumed to be a vertically integrated utility, the credit rating is assumed to be low-to-mid investment grade. If this were not the case, the CMA set out that the additional premium required is 50-100bps.
- **Global Financial Crisis (GFC):** There were large spikes in the cost of debt during the GFC. Market commentary has suggested that there may still be headwinds from this affecting financial markets and the experience of this and the impacts, for example, markets drying up and a reduced pace of growth, are relatively fresh in the memory. In making our assessment of the cost of capital, we bear in mind this potential impact.

N Ireland (UK)	COST OF DEBT	2. All-in Cost of Debt	D. CEPA Assessment

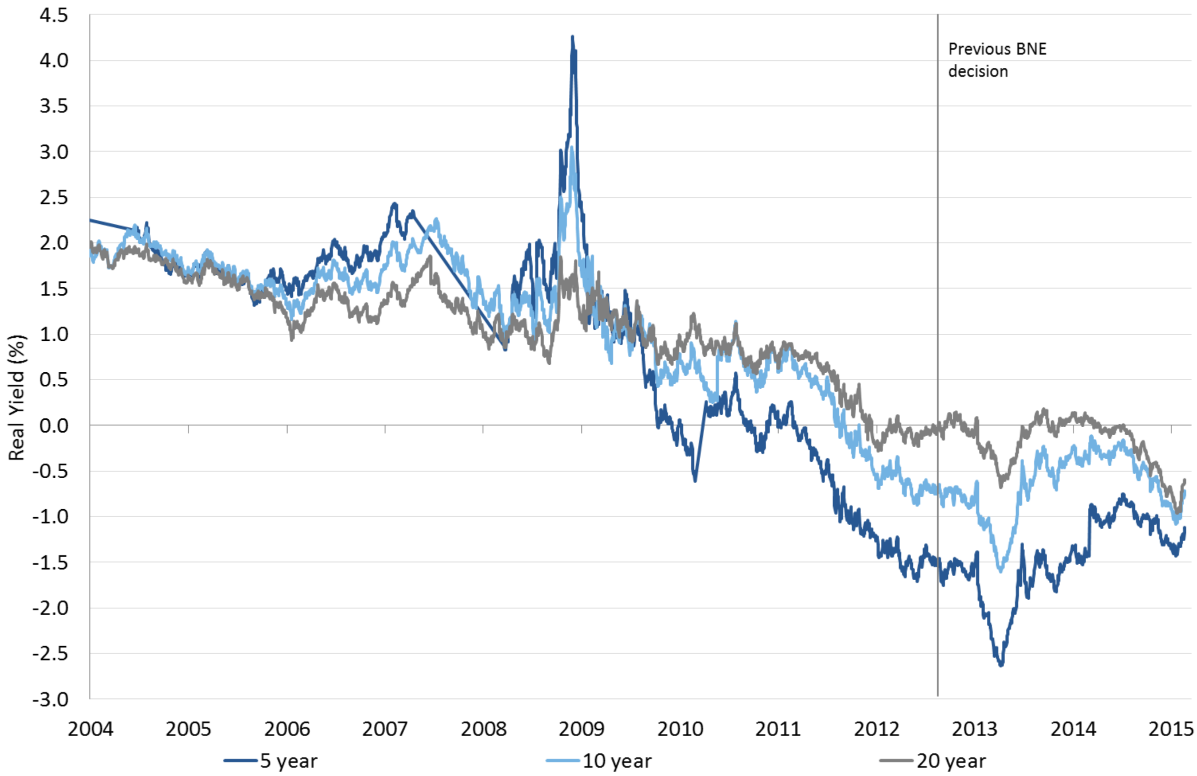
Our assessment of the all-in real cost of debt for NI utilises evidence of forward rates on ten year corporate debt with an addition for fees. This gives a lower bound of **0.75%**.

At the upper bound, we consider a longer term cost of debt averages and regulatory precedent to arrive at an upper bound of **2.25%**.

N Ireland (UK)	COST OF EQUITY	3. Risk-free rate	A. Market evidence

The CMA confirm in the NIE determination that the use of longer-term Index Linked Gilts (ILGs) is appropriate as a proxy for the risk-free rate. As our approach to setting the risk-free rate (i.e. with this applying only for the cost of equity) matches the CMA, we look at UK ILGs (see Figure B5 and Table B8 below) in our analysis for estimating the risk-free rate.

Figure B.5: UK Index-Linked Gilt yields



Source: Bloomberg

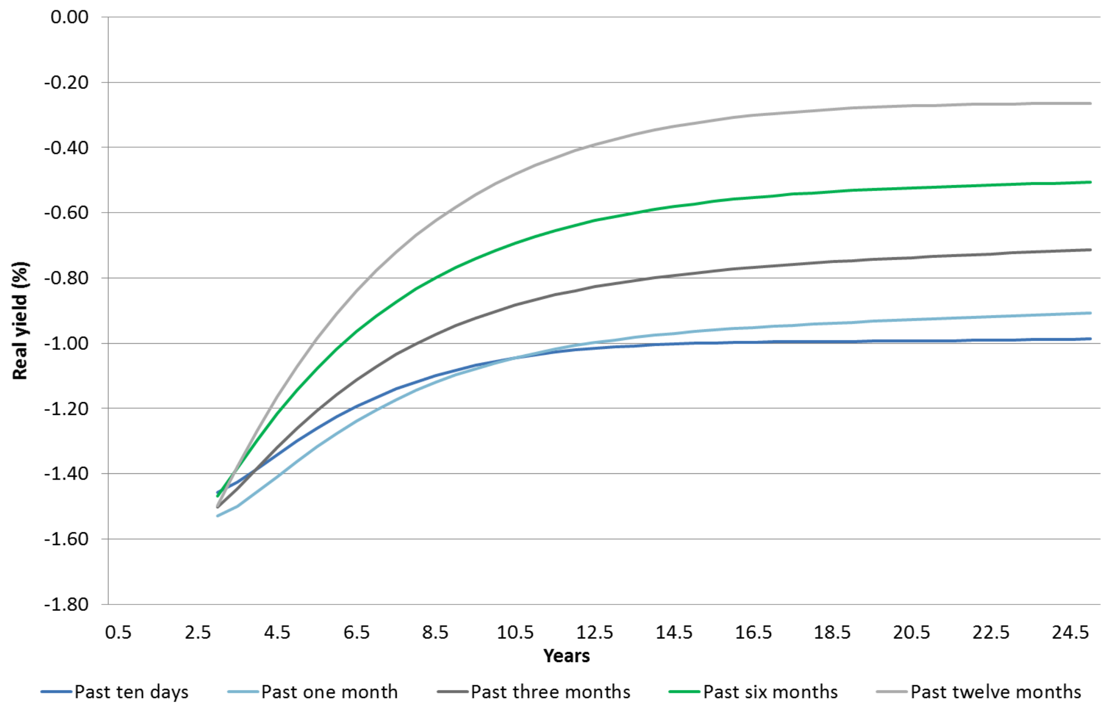
Table B.7: UK ILG yield averages

ILG tenor	Spot (20/2/15)	1yr average	2yr average	5yr average	10yr average
5 year	-1.14	-1.07	-1.43	-1.04	0.13
10 year	-0.73	-0.51	-0.62	-0.25	0.61
20 year	-0.61	-0.30	-0.21	0.14	0.70

Source: Bloomberg

As we are setting a longer-term risk-free rate, we focus more on trailing averages rather than the spot rate. However, the long-term trailing average is continuing to fall – at the start of the calendar year 2016, the ten-year trailing average will be 50bps lower than the time of the CMA NIE RP5 Final Determination. At the end of the calendar year 2016, the ten-year trailing average for the ten year ILG is forecast to be just 0.22%.

Figure B.6: UK Average Real Yield Curves over different time horizons (as of end-Jan 2015)



Source: Bank of England

Yields for the risk-free rate have fallen, with expectations pointing to limited increases in the low spot yields observed. Even using long term trailing averages, since the CMA NIE Final Determination, there is an argument that the risk-free rate has fallen further.

We can use these forward expectations to look at how a longer term trailing average may change. Market expectations on nominal ten year gilts point to an increase of c.125bps by the end of 2024 (our base case). We show the average over the twenty year period from 2005-2024 with ten years of historic data and ten years of expectations. We also look at sensitivities beyond this base case. For example, Variant A looks a case where rates rise twice as much as forecast (i.e. an increase of 250bps by the end of 2024).

Table 7.8: UK ILG yield averages

Case	Description	2005-2024	2015-2024
Base	Using market-derived forward expectations	0.40	-0.01
Variant A	Rates rise by 2.0x market expectations	0.78	0.72
Variant B	Rates rise by 3.0x market expectations	1.17	1.46
Variant C	Rates rise by 0.5x market expectations	0.20	-0.38
Variant D	Rates remain at current spot rate	0.01	-0.75

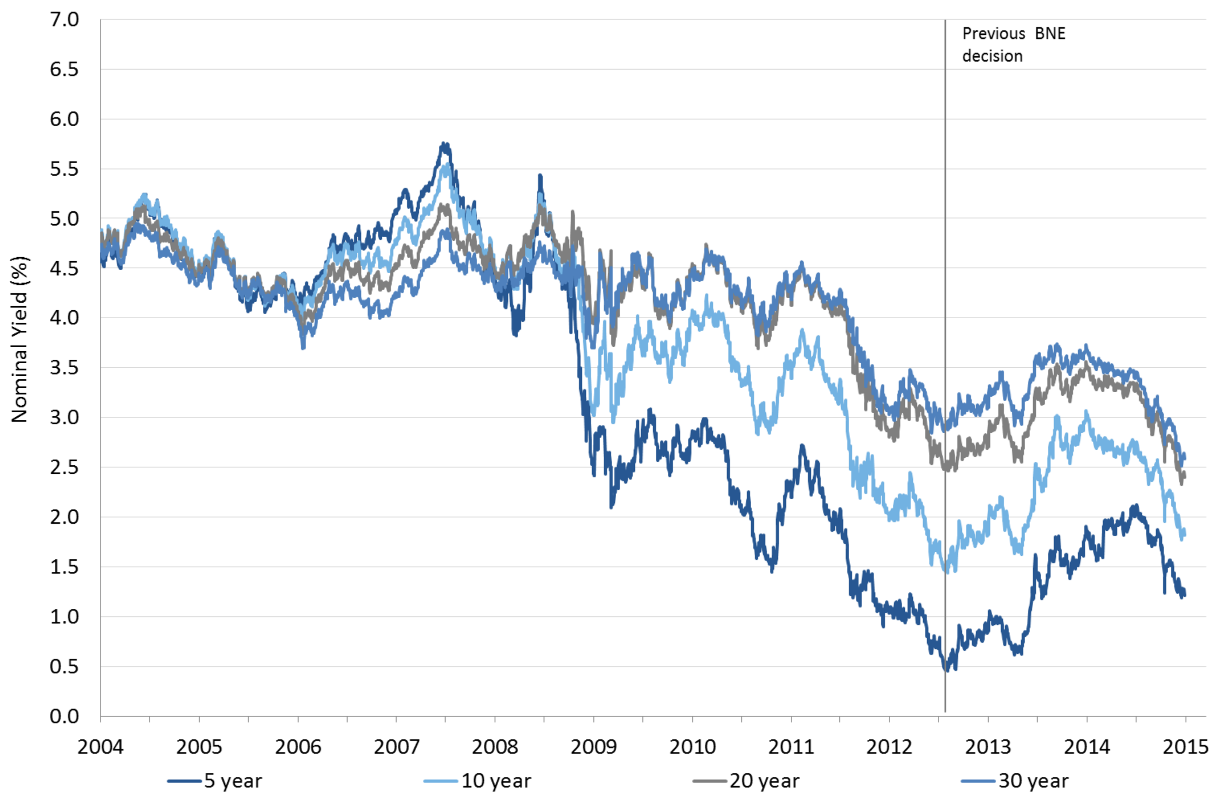
Source: Bloomberg

Our base case points to the risk-free rate averaging 0.40% over the period 2005-2024. This is only slightly below the current ten-year trailing average of 0.61% for ten-year ILGs. Our Variant B is our highest case and assumes rates rise by 375bps in the next decade[24]. If rates remain where they are, the twenty year average will be equal to 0.0% over the 2005-2024 period.

Nominal Gilts

We have cross-checked our findings on Index-Linked Gilts against Nominal Gilt yields in the UK. The nominal yield curve has flattened substantially in the last twelve months, reflecting expectations of reduced future rises. Both the nominal gilt yield and nominal yield curve are presented below.

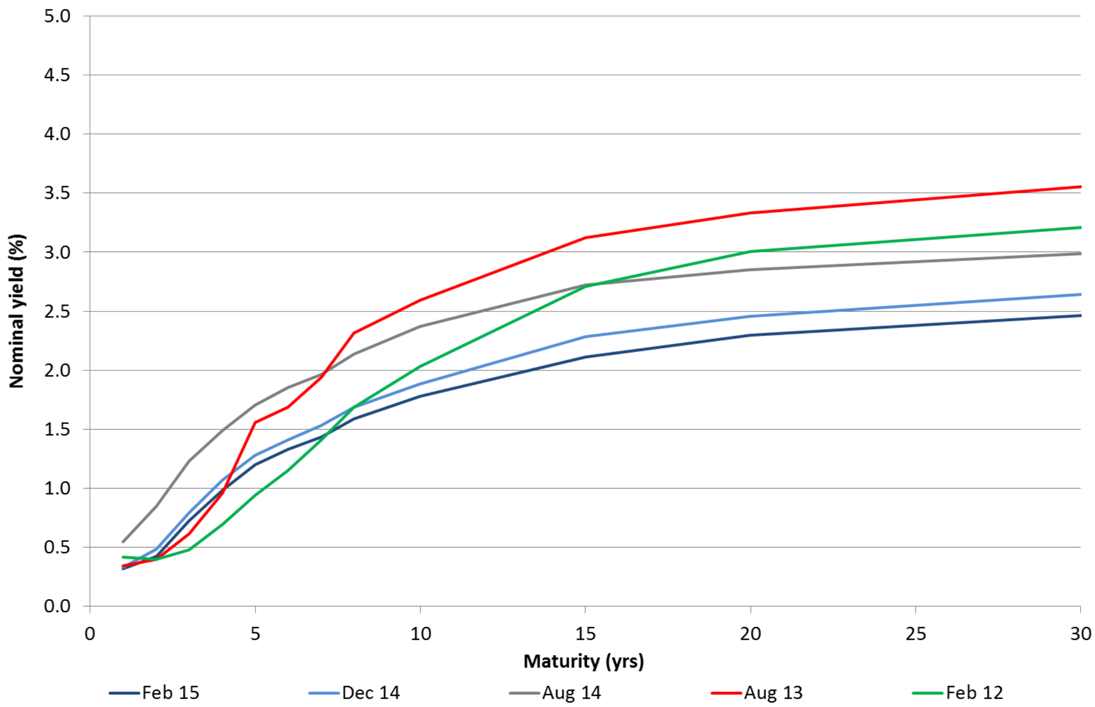
Figure B.7: UK Nominal Gilt yields



Source: Bloomberg

[24] The Financial Crisis saw a rise of 200bps at its peak.

Figure B.8: UK Nominal Yield Curve



Source: Bloomberg

N Ireland (UK)	COST OF EQUITY	3. Risk-free rate	B. Regulatory precedent

The below table captures recent UK regulatory precedent on the risk-free rate.

Table B.9: Regulatory determinations on the cost of debt in the UK

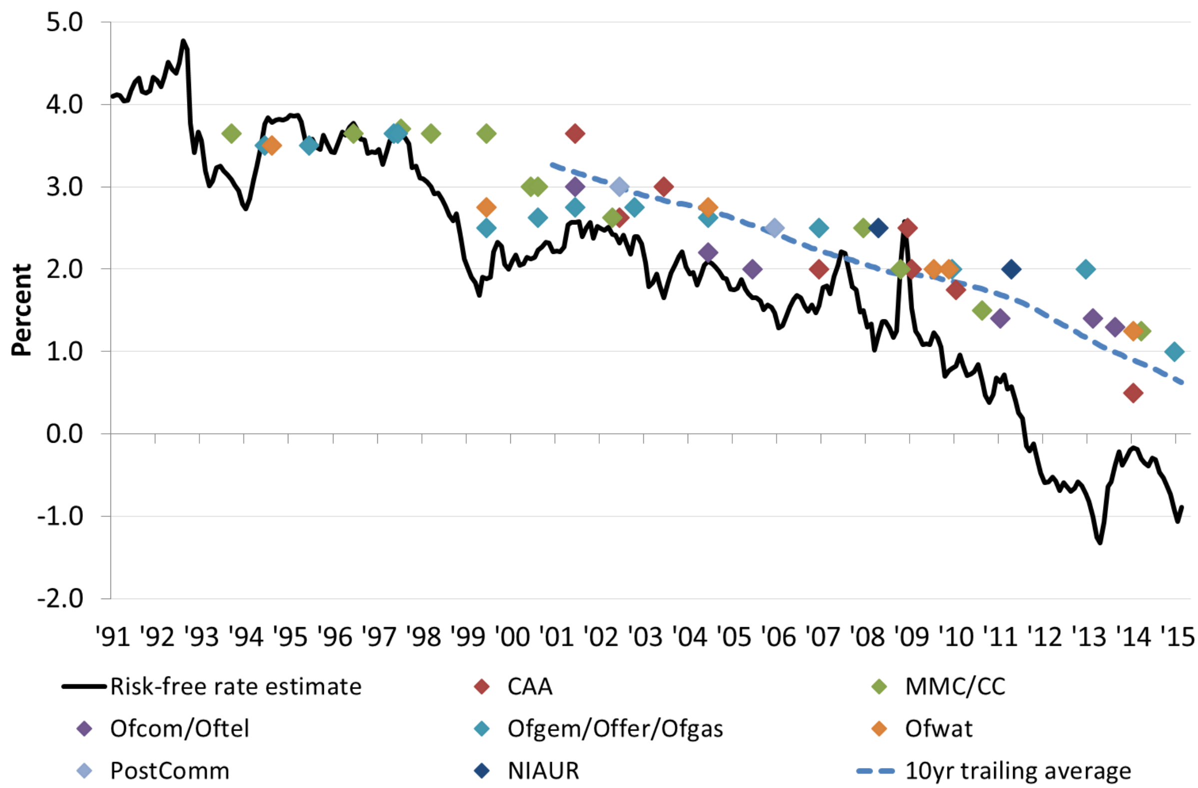
Regulator	Decision	Real risk-free rate
Ofwat	PR14 (2015-2020)	1.25%
Ofgem	RIIO ED1 (2015-2023)	1.00%*
Ofcom	Fixed Access - Openreach	1.30%
Ofcom	Fixed Access – BT Group	1.30%
Ofcom	Fixed Access – Rest of BT	1.30%
CMA	NIE T&D (2012-2017)	1.25%
CAA	Q6 – Heathrow (2014-2019)	0.50%
CAA	Q6 – Gatwick (2014-2019)	0.50%
ORR	PR13 (2014-2019)	1.75%
Ofgem	RIIO GD1 (2013-2021)	2.00%
Ofgem	RIIO T1 – Scottish TOs (2013-2021)	2.00%
Ofgem	RIIO T1 – NGET (2013-2021)	2.00%

Regulator	Decision	Real risk-free rate
Ofgem	RIIO T1 – NGGT (2013-2021)	2.00%
CER/NIAUR	Best New Entrant - NI (2013)	1.75%

*Note: * signifies implied figure*

Regulators have typically used risk-free rates which were approximate to the ten-year trailing average for ten year ILGs at the time of the decision. As this has fallen, the trend for the risk-free rate determined by regulators has also fallen. Due to the downwards movement in spot rates, we would expect the fall in the ten year average to continue, and maintaining the same regulatory approach would give lower risk-free rate estimates.

Figure B.9: UK risk-free rate estimates compared to ten-year zero coupon yield



Source: Bank of England, UK regulators

N Ireland (UK)	COST OF EQUITY	3. Risk-free rate	C. Commentary

- **Use of average period:** There are differences in over 100bps between current spot rates and ten year averages for different tenor of debt. Regulators have tended to utilise longer term averages for network price control determinations, noting the risks in setting an allowance based on more volatile spot rates. However, these longer averages have still exhibited changes, for example the ten year averages at the start of 2016 will be c.50bps lower than at the time of the CMA NIE Final Determination in April 2014.

- **Expectations:** Much has been made of the impact of Quantitative Easing (QE) on the risk-free rate. The effect has been estimated at c.100bps in the UK according to Bank of England analysis and a question discussed as part of the CMA NIE determination was whether the impact is temporary or whether it has been built into market rates. The view of Dimson, Marsh and Staunton (2014) is that these expectations have been built into prices, however the CMA adopted a higher range given the possibility that this was depressing yields temporarily. The flattening of the yield curve and the announcement of the ECB QE programme may suggest that an uplift would not be required at present.
- **Regulatory precedent:** The Civil Aviation Authority (CAA) for the Q6 price control adopted a real risk-free of 0.5%, a figure below the CMA NIE range. Both regulatory bodies set a risk-free rate for the cost of equity only.
- **Forward uplift:** We have discussed above the impact of expectations. When looking at movements in the risk-free rate, we consider forward rate evidence, pointing to a nominal increase of 20bps in the remainder of 2015 and a further 20bps increase in the calendar year 2016.
- **Uncertainty:** With the number of changes observed above, there is ongoing uncertainty around the risk-free rate, the cost of debt and equity returns.

N Ireland (UK)	COST OF EQUITY	3. Risk-free rate	D. CEPA Assessment

Our proposed range for the risk-free rate in NI is **0.5-1.5%**. This captures CMA precedent and changes in longer term averages for ILGs.

We note that the low end of our range does apply a historically low risk-free rate assumption for example relative to regulatory precedent. We believe such an assumption can be implied from current market evidence, but also note that the risk-free rate should be considered alongside the assumption that is made on the equity risk premium and therefore the total market return that is adopted in the cost of equity estimate.

We apply a 0.5% risk free rate assumption at the low end of the range as we consider it consistent with the equity risk premium assumption we apply (as detailed below) and a reasonable range for the total equity market return.

N Ireland (UK)	COST OF EQUITY	4. Equity Risk Premium	A. Market evidence

For our assessment of the equity risk premium, previous regulatory precedent has attached significant weight to evidence contained within the Credit Suisse Global Investment Returns Sourcebook. We look at evidence for the UK on equity returns since 1900.

Table B10: Equity risk premia 1900-2014

Country	Geometric (vs bill)	Arithmetic (vs bill)	Geometric (vs bond)	Arithmetic (vs bond)
UK	4.3%	6.1%	3.7%	5.0%

Source: DMS

As our risk-free rate is based on evidence relating to bonds, it is appropriate to consider the equity risk premium relative to bonds (as opposed to bills).

Real equity returns in the UK from 1900-2014 are 5.3% using a geometric mean and 7.1% using an arithmetic mean. Using historic return as a proxy for expected returns is one method for calculating the equity risk premium.

N Ireland (UK)	COST OF EQUITY	4. Equity Risk Premium	B. Regulatory precedent

Table B.11 below provides recent regulatory precedent on cost of equity parameters in the UK.

Table B.11: Regulatory determinations on the post-tax cost of equity in the UK

Regulator	Decision	ERP	Equity beta	Post-tax Cost of Equity
United Kingdom				
Ofwat	PR14 (2015-2020)	5.50%	0.80	5.65%
Ofgem	RIIO ED1 (2015-2023)	5.00%*	0.90*	6.00%
Ofcom	Fixed Access - Openreach	5.00%	0.69	4.75%
Ofcom	Fixed Access – BT Group	5.00%	1.01	6.35%
Ofcom	Fixed Access – Rest of BT	5.00%	1.17	7.15%
CMA	NIE T&D (2012-2017)	5.00%	0.75	4.81%
CAA	Q6 – Heathrow (2014-2019)	5.75%	1.10	6.80%
CAA	Q6 – Gatwick (2014-2019)	5.75%	1.12	7.00%
ORR	PR13 (2014-2019)	5.00%	0.95	6.50%
Ofgem	RIIO GD1 (2013-2021)	5.25%	0.90	6.70%
Ofgem	RIIO T1 – Scottish TOs (2013-2021)	5.25%	0.95	7.00%
Ofgem	RIIO T1 – NGET (2013-2021)	5.25%	0.95	7.00%
Ofgem	RIIO T1 – NGGT (2013-2021)	5.25%	0.91	6.80%
CER/NIAUR	Best New Entrant - NI (2013)	4.75%	1.25	7.70%

*Note: * signifies implied figure*

The regulation of electricity interconnection has been discussed within respect to the cost of debt. The cost of debt was assumed to be equivalent to returns at the floor, whilst the cost of equity equivalent to a cap on returns. A long-term estimate of equity returns was used, with the risk-free rate used in Ofgem's RIIO GD1 and T1 determination (2.0%), reduced by 40bps to account for the RPI inflation effect[25], with an ERP of 5.2%.

N Ireland (UK)	COST OF EQUITY	4. Equity Risk Premium	C. Commentary

- **Approach to calculating an ERP:** In estimating the equity premium, we adopt an approach which is similar to the CMA, in that we assess the total market return and then subtract the risk-free rate to arrive at an ERP.
- **Long term averages:** We agree with the approach of looking at long term evidence in assessing equity returns. A key source of information for this is the Credit Suisse Global Investment Returns Sourcebook, which contains data for different countries back to 1900. Depending on whether the arithmetic or geometric return is considered, there is a significant difference in results.
- **Falls in expected returns:** The authors of the Credit Suisse Global Investment Returns Sourcebook find that the expected equity risk premium at present is approximately 100bps lower than indicated by the historical average.
- **Fall in regulated cost of equity:** We have seen large falls in recent regulatory precedent on the cost of equity, for examples a 70bps reduction for the RIIO-ED1 price control and over 130bps for the PR14 price control. This has been driven by market evidence and the CMA NIE determination.
- **QE and risk-appetite:** Anecdotal evidence points to QE having a substantial positive effect on equity markets returns. These returns may come at the cost of lower future equity returns, as noted by Mervyn King[26].
- **Expected returns:** The returns expected from an equity investment depends on a range of aspects, such as the level of gearing, investor profile, technology and stage of the project life cycle. As such, it is difficult to arrive at a precise figure for expected equity returns.

N Ireland (UK)	COST OF EQUITY	4. Equity Risk Premium	D. CEPA Assessment

Our estimate for the total equity market return is 5.5-6.5%, consistent with the range used in the CMA NIE RP5 determination. Evidence would indicate that the lower end of this range

[25] This represents an increase in the RPI inflation estimate that is consistent with the CPI target of 2.0%. An increase in the RPI inflation figure leads to a lower real risk-free rate.

[26]http://blogs.ft.com/gavyndavies/2013/05/26/what-will-happen-to-markets-when-qe-ends/?infernofullcomment=1&SID=google

would be appropriate for our assessment of the cost of equity. Based on our risk-free rate range of 0.5-1.5%, this yields an ERP of **5.0%**.

N Ireland (UK)	COST OF EQUITY	5. Equity Beta	A. Market evidence

We calculate a two-year daily rolling beta, averaged over different time periods, based on listed company data. There is a limited number of listed UK companies, with several of those listed below having operations outside of UK regulated sectors. We include Alkane, an independent power generation, and Drax, another power generator.

Table B12: Beta estimation

	Asset Beta Average (as of 20/2/15)			Equity Beta at 50% notional gearing^		
Company	**1yr**	**3yr**	**5yr**	**1yr**	**3yr**	**5yr**
National Grid	0.39	0.29	0.28	0.78	0.58	0.56
SSE	0.40	0.38	0.37	0.80	0.75	0.73
United Utilities	0.28	0.23	0.22	0.55	0.46	0.45
Severn Trent	0.32	0.26	0.25	0.64	0.52	0.49
Alkane	0.30	0.26	0.20	0.60	0.53	0.40
Drax	0.62	0.60	0.59	1.25	1.20	1.19

Source: Bloomberg. Note: ^ assumes no debt beta as part of this calculation.

The asset betas are re-levered using a market capitalisation based estimate of gearing. The equity beta is sensitive to the level of gearing assumed, whilst the asset beta assumes the asset is entirely equity financed.

The CMA has recently published analysis on the beta of energy firms. This data is presented below. The approach adopted is slightly different to our estimations above, in that monthly and quarterly betas rather than daily betas have been used. The CMA betas have been calculated over the time period January 2007 to March 2014.

Table B13: Asset betas of energy firms 2007-2014

Company	Asset beta - monthly	Asset beta - quarterly
Centrica	0.42	0.41
SSE	0.36	0.24
EDF	0.75	0.67
E.ON	0.70	0.50
Iberdrola	0.66	0.55
RWE npower	0.67	0.45

Company	Asset beta - monthly	Asset beta - quarterly
GDF Suez	0.54	0.45
Drax	0.40	0.34
AES Corp	0.60	0.71
AEP Corp	0.33	0.35
Telecom Plus	0.01	-0.33
Good Energy	0.57	-1.60
Just Energy	1.18	0.91
Crius Energy Trust	-0.58	1.44

Source: CMA analysis, Bloomberg

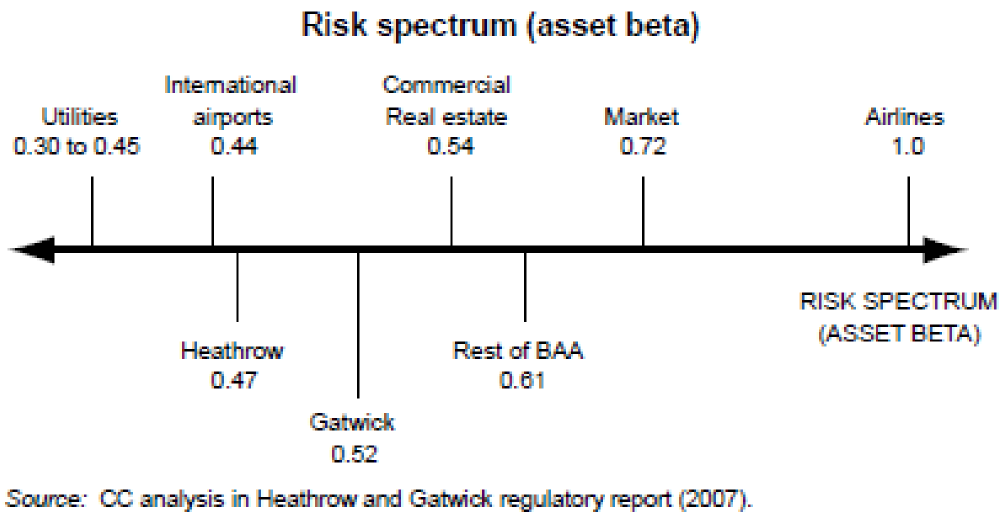
In their backwards-looking analysis, the asset beta for generation companies has been estimated at 0.5-0.6 by the CMA. The translation of the asset beta into an equity beta is dependent on the level of gearing assumed for the BNE peaking plant.

N Ireland (UK)	COST OF EQUITY	5. Equity Beta	B. Regulatory precedent

In translating our asset beta into an equity beta, the use of a debt beta has an impact. In the NIE RP5 Final Determination, the CMA used a debt beta, Ofwat has used a debt beta at PR14 and it is our understanding that Ofgem used a debt beta of 0.1 for RIIO ED1. If a debt beta of 0.1 is used for our analysis, the 1.20-1.30 equity beta assumption in our BNE 2013 report corresponds to an asset beta of 0.54-0.58 at the notional gearing level.

In the CMA NIE RP5 determination paper, the following spectrum of asset betas is presented – this comes from a previous CMA determination.

Figure B.10: Regulatory spectrum on asset betas



Source: CMA

We believe that an asset beta of 0.5-0.6 for the BNE would be consistent with this analysis. There are relatively few standalone companies we can observe equity betas for, who share characteristics with the BNE plant. In terms of observed asset betas, the CMA analysis on GB companies showed utility companies operating under a price control were at the bottom end of the range presented above.

Table B14: Regulatory determinations on the post-tax cost of equity in the UK

Regulator	Decision	ERP	Equity beta	Post-tax Cost of Equity
United Kingdom				
Ofwat	PR14 (2015-2020)	5.50%	0.80	5.65%
Ofgem	RIIO ED1 (2015-2023)*	5.00%	0.90	6.00%
Ofcom	Fixed Access - Openreach	5.00%	0.69	4.75%
Ofcom	Fixed Access – BT Group	5.00%	1.01	6.35%
Ofcom	Fixed Access – Rest of BT	5.00%	1.17	7.15%
CMA	NIE T&D (2012-2017)	5.00%	0.75	4.81%
CAA	Q6 – Heathrow (2014-2019)	5.75%	1.10	6.80%
CAA	Q6 – Gatwick (2014-2019)	5.75%	1.12	7.00%
ORR	PR13 (2014-2019)	5.00%	0.95	6.50%
Ofgem	RIIO GD1 (2013-2021)	5.25%	0.90	6.70%
Ofgem	RIIO T1 – Scottish TOs (2013-2021)	5.25%	0.95	7.00%

Regulator	Decision	ERP	Equity beta	Post-tax Cost of Equity
Ofgem	RIIO T1 – NGET (2013-2021)	5.25%	0.95	7.00%
Ofgem	RIIO T1 – NGGT (2013-2021)	5.25%	0.91	6.80%
CER/NIAUR	Best New Entrant - NI (2013)	4.75%	1.25	7.70%

*Note: * signifies implied*

In addition to onshore regulatory precedent, we can also consider the cap and floor regime which applies to interconnectors as an example of regulatory precedent. For the Nemo interconnector, the Drax equity beta re-levered to 50% gearing was used, giving a 1.25 equity beta at the cap (uppermost limit of potential returns).

N Ireland (UK)	COST OF EQUITY	5. Equity Beta	C. Commentary

- **CMA precedent:** The CMA have recently looked at the cost of capital for energy generators, finding that the appropriate asset beta for both vertically integrated energy companies and standalone generators is 0.5-0.6.
- **Impact of gearing:** Drax, a power generator, has very low leverage (0-5%) compared to our other utility sector comparators. We can then take the observed equity beta, and re-lever this based on an assumed gearing figure to arrive at a more consistent equity beta figure for the BNE. However, this assumes that the equity beta increases with gearing with a CAPM relationship. In the water sector, there were large increases in gearing with little change to observable equity betas.
- **Generation profitability:** CMA analysis as part of the GB energy market investigation indicates that in recent years, large GB vertically integrated energy companies have made returns below a credible cost of capital, and in some cases negative. This could indicate that there are risks around the investment that mean investors require higher returns.
- **Disconnect between market evidence and regulatory precedent:** Regulators in the UK have tended to opt for equity beta *allowances* which are above those indicated by market evidence. Ofwat for the PR14 price control cut the asset beta by a quarter, however Ofgem for RIIO-ED1 did not change the equity or asset beta.
- **Rise in asset beta:** The one year averages for our market evidence are higher than three or five years averages. We tend to focus upon longer term averages for other cost of capital parameters, so would adopt a similar approach here, whilst being aware of the recent increase.

N Ireland (UK)	COST OF EQUITY	5. Equity Beta	D. CEPA Assessment

We propose to use an asset beta of 0.5-0.6 for the BNE 2016. This mirrors the figures set out by the CMA in their recent analysis on energy generation. This means we broaden the range for the asset beta assumed for the BNE in 2013 of 0.54-0.58. Combining the notional gearing assumption and the asset beta range gives an equity beta range of 1.10-1.35.

In combining our estimates to arrive at the cost of capital, we use an average of our lower and upper bound of the risk-free rate for both cases. For NI, this gives a post-tax cost of equity of 6.50-7.75%. This is equivalent to a pre-tax cost of equity of **8.13-9.69%**.

B.6. WACC parameters for Republic of Ireland (RoI)

In this section we look at the five building block components for the cost of capital for the RoI. These five components are:

1. Notional gearing
2. Cost of Debt
3. Risk-free rate
4. Equity Risk Premium
5. Equity Beta

For each of these components, we break our analysis down into four categories:

A. Market Evidence
B. Regulatory Precedent
C. Commentary
D. CEPA Assessment

RoI	GEARING	1. Notional gearing	A. Market evidence

A notional gearing level must be assumed for the BNE. We believe that the evidence presented for NI is relevant for the RoI.

RoI	GEARING	1. Notional gearing	B. Regulatory precedent

The table below presents regulatory precedent on gearing in the RoI for regulated "network" price control sectors.

Table B15: Regulatory determinations on gearing

Regulator	Decision	Gearing (%)
Republic of Ireland		
IAA	DAA Charges (2015-2019)	50%
ComReg	Mobile and fixed line communications (Dec 2014)	30%
CER	PR3 Mid-term review (2014-2015)	55%
CER	PR3 for ESB and EirGrid (2011-2015)	55%
CER	PC3 for BGN (2012-2017)	55%
CER/NIAUR	Best New Entrant – RoI (2013)	60%

RoI	GEARING	1. Notional gearing	C. Commentary

We have discussed the level of gearing for NI. Please see this section for further analysis.

RoI	GEARING	1. Notional gearing	D. CEPA Assessment

Our notional gearing level is equivalent in both jurisdictions. Based on evidence we have considered, our notional gearing assumption has remained at **60%** for the 2016 BNE.

RoI	COST OF DEBT	2. All-in Cost of Debt	A. Market evidence

As discussed in our estimation of the cost of debt for the UK jurisdiction, we calculate an all-in cost of debt rather than build up a cost of debt using a risk-free rate and debt premium.

RoI evidence

We consider both country/regional level benchmarks as well as looking at individual utility bonds in our assessment of the cost of debt. The RoI does not have sufficient volumes of issuance to have as reliable benchmarks as some other countries – therefore we utilise Eurozone data and cross-check this against Irish bonds.

Utility bond issuance

The table below summarises examples of utility bond issuance in the RoI.

Table B16: Utility bond data in Ireland

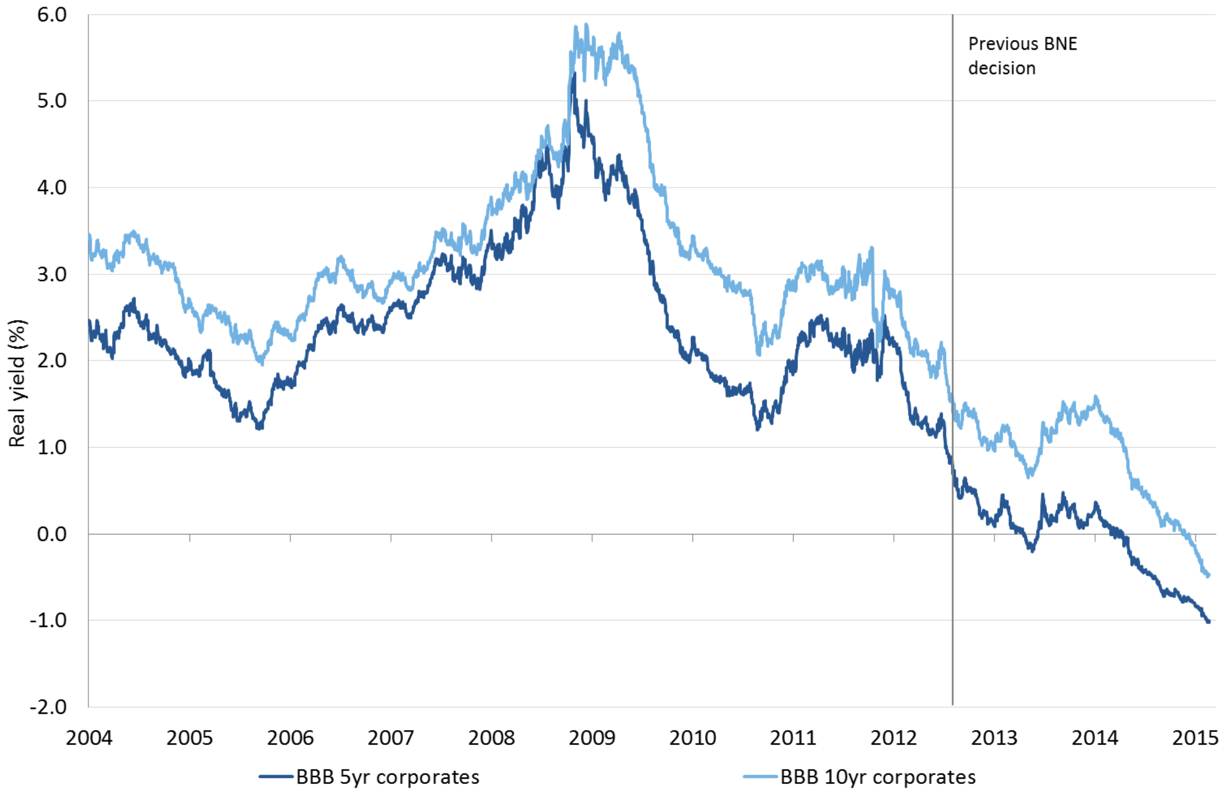
Company	Maturity	Amount	Credit rating	Yield to maturity today (nominal)	Spread to gilt today
ESB	09/2017	£600m	BBB+	0.36%	53bps
ESB	11/2019	£500m	BBB+	0.52%	69bps
ESB	01/2024	£300m	BBB+	1.14%	95bps

Source: Bloomberg

Benchmarks

As illustrated in Figure B.11 below, the corporate debt yields at the Eurozone level have fallen into negative territory in real terms, even for BBB rated debt. Even after taking into account expected increases in gilts, the Eurozone BBB real corporate debt yield is forecast to be at zero per cent (prior to the inclusion of any fees).

Figure B.11: Eurozone BBB rated corporate debt yields

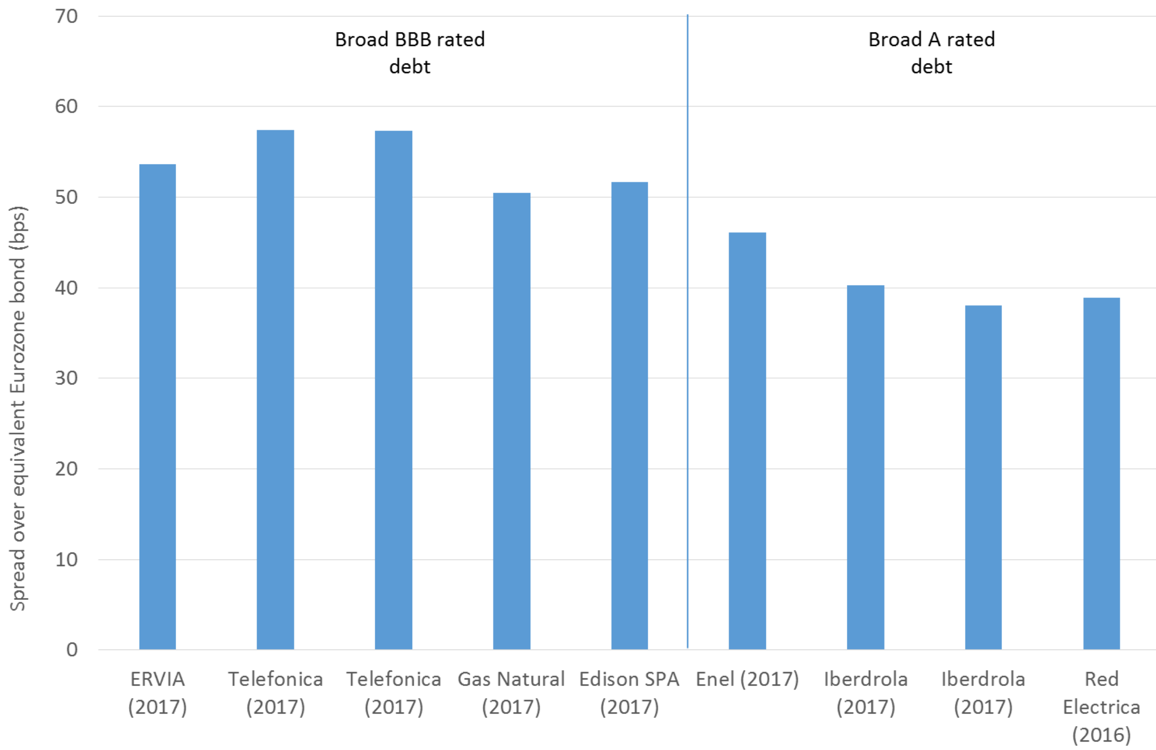


Source: Bloomberg

In previous BNE reports (2013 and 2012), we looked at the spread of periphery country Eurozone debt expiring in 2017 relative to gilts. For BBB rated debt, the spread was c.330bps over gilts, whilst for A rated debt, the spread over gilts was c.250bps. Bond spreads at present are shown below. Although the time to maturity has fallen to only a couple of years, there has been a significant narrowing of spreads in the period since the previous BNE report and the ERVIA[27] bond has a yield similar to other BBB rated debt.

[27] Previously Bord Gáis Éireann.

Figure B.12: Spreads on investment grade debt in Eurozone periphery countries



Source: Bloomberg (as of 12 March 2015)

RoI	COST OF DEBT	2. All-in Cost of Debt	B. Regulatory precedent

In the table below we show regulatory precedent on the cost of debt in Ireland. For the BNE we focus on the cost of new debt given the asset profile, which leads to greater volatility than for assets with embedded debt.

Table B17: Regulatory determinations on the cost of debt in Ireland

Regulator	Decision	Risk-free rate	Cost of debt (all)	Cost of new debt
Republic of Ireland				
IAA	DAA Charges (2015-2019)	1.5%	3.00%	3.00%
ComReg	Mobile and fixed line communications (Dec 2014)	2.1%	3.55%	-
CER	PR3 Mid-term review (2014-2015)	2.63%*	3.75%	-
CER	PR3 for ESB and EirGrid (2011-2015)	3.29%	4.50%	-
CER	PC3 for BGN (2012-2017)	4.5%	3.80%	-
CER/NIAUR	Best New Entrant – RoI (2013)	4.5%	-	7.00%

*Note: * denotes implied value*

RoI	COST OF DEBT	2. All-in Cost of Debt	C. Commentary

- **More limited evidence base:** Compared to the UK, Ireland has a more limited evidence base when looking at the cost of debt. The markets are not equivalent and the lack of an Irish cost of debt benchmark makes analysis more difficult.
- **Fragility:** Moody's note the resurgence in the performance of the Irish economy, but note that there are still some ongoing issues and uncertainties – for example, a large proportion of non-performing loans for Irish banks. There have been changes in Ireland's sovereign credit rating over the past three to four years, which we would expect to link through in part to the perception of the Irish economy.
- **Negative yields at European level:** Market evidence on the cost of debt shows negative real yields for BBB corporates in the Eurozone for shorter maturities. Despite regulatory precedent falling significantly, there is still a large discrepancy between recent precedent and this market evidence. The question of normalisation is something that we take into account, however noting our assumption that debt would be taken out by the BNE in the calendar year 2016.

RoI	COST OF DEBT	2. All-in Cost of Debt	D. CEPA Assessment

We believe that a cost of (new) debt of **1.00-3.00%** is appropriate. This is a wider range than we have adopted for the NI jurisdiction. This reflects a wider difference between current evidence and longer term evidence.

RoI	COST OF EQUITY	3. Risk-free rate	A. Market evidence

As with NI, we use the risk-free rate only in setting our cost of equity, with the cost of debt set on an overall basis. We look at a mixture of RoI and Eurozone market evidence in making our assessment of the risk-free rate.

RoI evidence

In February 2015, the Irish government issued its first ever 30 year bond. This was priced with a nominal yield of 2.09% and was cheaper than the yield at issue for a five-year sovereign bond issued in late 2014. Based on long-term inflation expectations[28], this equates to a real risk-free rate of 0.2% for 30 year debt. The upward sloping yield curve would indicate a lower real rate would have been achieved for lesser tenor bonds.

[28] This is based on the ECB Quarterly Survey of Independent Forecasters.

Figure B.13: Irish nominal gilts deflated by inflation expectations

Source: Bloomberg, ECB

Table B.18: Irish real yield averages (nominal yields deflated by inflation expectations)

ILG tenor	Spot (18/2/15)	1yr average	2yr average	5yr average	10yr average
5 year	-1.36	-0.87	-0.12	2.62	2.21
10 year	-0.63	0.39	1.15	3.56	2.92
20 year	-0.22	0.92	1.68	3.79	3.18

Source: Bloomberg

The Irish spike in yields occurred in mid-2011, two years later than the spike in yields observed in the UK. This means that the five year average is still high compared to spot rates. The issue here from a regulatory perspective is the discrepancy between the spot rate and longer term trailing averages.

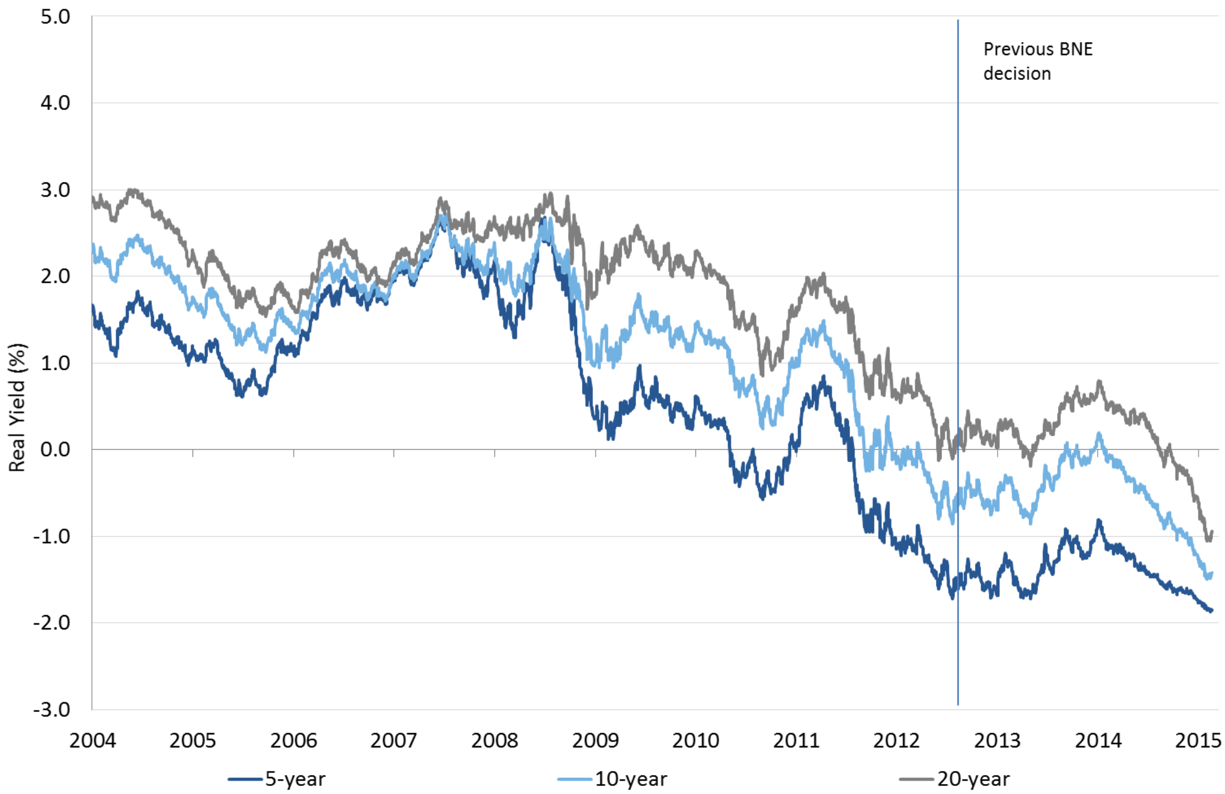
Eurozone evidence

Prior to the breakout of the financial crisis in late-2008, there was a perception that investors treated sovereign risk as essentially identical anywhere inside the single Euro-zone currency zone. The global financial crisis represented a structural break in this regard, with Irish sovereign debt being significantly above that for Germany given different perceptions in risk.

However, as discussed above, the large differences in yields on Irish and German government sovereign debt that were observed in the past few years are not observed at present.

Real yields on German bunds are shown in the figure below.

Figure B.14: German nominal gilts deflated by inflation expectations



Source: Bloomberg, ECB

Table B19: German real yield averages

ILG tenor	Spot (18/2/15)	1yr average	2yr average	5yr average	10yr average
5 year	-1.86	-1.49	-1.38	-0.90	0.24
10 year	-1.42	-0.75	-0.51	-0.03	0.87
20 year	-0.94	-0.05	0.16	0.67	1.46

Source: Bloomberg

RoI relative to wider Eurozone evidence

The trailing average yields for Ireland are materially above those for Germany (c.200bps for five and ten year gilts). However, as we have discussed above, spot rates for Irish and German gilts have become much closer.

Table B20: Irish real yield minus German real yield

ILG tenor	Spot (18/2/15)	1yr average	2yr average	5yr average	10yr average
5 year	0.50	0.62	1.26	3.52	1.97
10 year	0.79	1.14	1.66	3.59	2.05
20 year	0.72	0.97	1.52	3.12	1.72

Source: Bloomberg

RoI	COST OF EQUITY	3. Risk-free rate	B. Regulatory precedent

The table below provides the real risk-free rate used in recent Irish regulatory precedent. The higher rates reflect the spike in Irish yields, focusing on the Irish rather than Eurozone economy in setting the risk-free rate.

Table B21: Regulatory determinations on the risk free rate

Regulator	Decision	Real risk-free rate (%)
Republic of Ireland		
IAA	DAA Charges (2015-2019)	1.5%
ComReg	Mobile and fixed line communications (Dec 2014)	2.1%
CER	PR3 Mid-term review (2014-2015)	2.6%*
CER	PR3 for ESB and EirGrid (2011-2015)	3.3%
CER	PC3 for BGN (2012-2017)	4.5%
CER/NIAUR	Best New Entrant – RoI (2013)	4.5%

*Note: * denotes implied value*

RoI	COST OF EQUITY	3. Risk-free rate	C. Commentary

- **Consistency of approach:** At the time when the yield on Irish gilts rose sharply and spot rates were above the historical average, greater weight appeared to be placed on these spots rate. However, when the spot rate has been below the longer term average, the majority of regulators have focussed upon longer term averages as a way of providing greater certainty. There are inconsistencies in such an approach. The question is whether such an approach is warranted – one justification for this could be that there is a greater risk in setting the cost of capital too low (with companies being unable to finance themselves) compared to being too high (higher bills for consumers). This allocation of risk to consumers rather than companies may in the longer term bring down the cost of capital investors require.
- **Country premium:** The large differential observed between Ireland and Germany sovereign yields in recent years has for the most part disappeared at present. However

Ireland's lower credit rating means that the countries are not considered the same in terms of creditor risk.

- **Inflation measure:** There is a significant difference between the current rate of inflation and longer term expectations. Annual inflation in the Eurozone is at present negative, whilst long term inflation expectations remain stable at 1.8% p.a. In setting a real-risk free rate, we focus on the appropriate time period to include in our analysis. The inflation measure used matters when considering evidence of yields on nominal bonds as a measure of the risk-free rate.

RoI	COST OF EQUITY	3. Risk-free rate	D. CEPA Assessment

As noted in our previous discussion of the risk-free rate for NI, we continue to believe that a longer term average is appropriate for setting the risk-free rate. At our lower bound, we adopt a real risk-free rate of 1.0%. This figure would assume that RoI is coupled with the Eurozone. For our upper bound, we adopt a figure of 2.5% for the RoI. In this state of the world, we rely on Irish data, but this upper bound is more reflective of the crisis effect re-emerging. We welcome views on whether a risk-free rate of **1.0-2.5%** is appropriate.

RoI	COST OF EQUITY	4. Equity Risk Premium	A. Market evidence

We look at evidence from the Credit Suisse Global Investment Returns Sourcebook 2015, as an example of historical returns and comparison to expected returns noted here in Ireland, Germany and the World.

Table B22: Real returns (geometric) for a one-year holding period

Country	Time period	Equities	Bonds	Bills
Ireland	2000-2014	0.5%	6.0%	0.1%
	1990-1999	11.8%	8.2%	5.4%
	1900-2014	4.2%	1.6%	0.7%
Germany	2000-2014	1.5%	7.5%	0.5%
	1990-1999	9.8%	5.3%	3.5%
	1900-2014	3.2%	-1.4%	-2.4%
World	2000-2014	1.8%	5.5%	-0.4%
	1990-1999	7.8%	6.7%	1.9%
	1900-2014	5.2%	1.9%	0.9%

Source: DMS 2015

These returns are based on a geometric average. An arithmetic average is also presented, which is higher than the geometric mean. The differences are shown for equity risk premia calculated over both bills and bonds. As our risk-free rate is calculated using bonds, our estimation of the equity risk premium should consider premia over bonds rather than bills.

Table B23: Equity risk premia 1900-2014

Country	Geometric (vs bill)	Arithmetic (vs bill)	Geometric (vs bond)	Arithmetic (vs bond)
Ireland	3.5%	5.8%	2.6%	4.5%
Germany	6.0%	9.9%	5.0%	8.4%
World	4.3%	5.7%	3.2%	4.5%

Source: DMS 2015

RoI	COST OF EQUITY	4. Equity Risk Premium	B. Regulatory precedent

The table of regulatory precedent below shows a wide range for the total equity market return, with a range of 275bps in recent regulatory precedent. To some extent this reflects the use of implicit and explicit country risk premia.

Table B24: Regulatory determinations on the post-tax cost of equity in Ireland

Regulator	Decision	ERP	Risk-free rate	Total market return
Republic of Ireland				
IAA	DAA Charges (2015-2019)	5.00%	1.50%	6.50%
ComReg	Mobile and fixed line communications (Dec 2014)	5.00%	2.10%	7.10%
CER	PR3 Mid-term review (2014-2015)	5.20%	2.63%	7.83%
CER	PR3 for ESB and EirGrid (2011-2015)	5.20%	3.29%	8.59%
CER	PC3 for BGN (2012-2017)	4.75%	4.50%	9.25%
CER/NIAUR	Best New Entrant – RoI (2013)	4.75%	4.50%	9.25%

RoI	COST OF EQUITY	4. Equity Risk Premium	C. Commentary

- **Approach to calculating an ERP:** In estimating the equity premium, we adopt an approach which is similar to the CMA in assessing the total equity market return and then subtracting the risk-free rate to arrive at an ERP. The ERP is forward looking, however, we primarily utilise historic information, cross-checked against more forward-looking evidence.
- **Long term averages:** We agree with the approach of looking at long term evidence in assessing equity returns. A key source of information for this is the Credit Suisse Global

Investment Returns Sourcebook, which contains data for different countries back to 1900. Depending on whether the arithmetic or geometric return is considered, there is a significant difference in results. Using both bonds and bills gives a total market return of no more than 6.5% using historical evidence.

RoI	COST OF EQUITY	4. Equity Risk Premium	D. CEPA Assessment

We adopt an Equity Risk Premium of **4.5%** for the RoI. This is 50bps lower than for NI, but reflects the higher risk-free rate used for RoI relative to NI and a view of the total equity market return. This also reflects evidence from the Credit Suisse Global Investment Returns Yearbook. This figure is below recent regulatory precedent, but higher than historical market evidence when looking at the total Irish market return.

RoI	COST OF EQUITY	5. Equity Beta	A. Market evidence

See market evidence presented for the appropriate equity beta for NI.

RoI	COST OF EQUITY	5. Equity Beta	B. Regulatory precedent

The table below summarises recent regulatory precedent in RoI on parameters used to calculate the cost of equity.

Table B25: Regulatory determinations on the post-tax cost of equity in Ireland

Regulator	Decision	Gearing	Equity beta	Post-tax Cost of Equity
Republic of Ireland				
IAA	DAA Charges (2015-2019)	50%	1.20	7.50%
ComReg	Mobile and fixed line communications (Dec 2014)	30%	0.93	6.75%
CER	PR3 Mid-term review (2014-2015)	55%	0.67	6.77%
CER	PR3 for ESB and EirGrid (2011-2015)	55%	0.67	6.12%
CER	PC3 for BGN (2012-2017)	55%	0.78	8.05%
CER/NIAUR	Best New Entrant – RoI (2013)	60%	1.25	10.35%

These decisions for the equity beta are driven by the level of gearing. With the exception of the ComReg decision, the level of notional gearing is 50-60%.

RoI	COST OF EQUITY	5. Equity Beta	C. Commentary

As per the approach adopted in previous determinations for the BNE, we assume the same asset beta for both the Irish and Northern Irish jurisdictions.

RoI	COST OF EQUITY	5. Equity Beta	D. CEPA Assessment

Our estimate for the asset beta is 0.50-0.60. Based on a debt beta of 0.1, this gives an equity beta at our revised notional gearing (60%) of 1.10-1.35.

Using an average of the high and low values of our range for the risk-free rate, this would give a post-tax cost of equity range of 6.70-7.83% for the RoI. This equates to a pre-tax cost of equity of **7.66-8.94%**.

B.7. Taxation

CEPA is of the view that the WACC is not necessarily the most appropriate mechanism to allow for taxation costs and that there is merit in forecasting actual taxation costs and allowing for these through BNE costs estimation. However, we recognise that given the RAs have adopted a pre-tax WACC approach in previous determinations and that this is for a notional BNE, for which forecasting actual taxation cost would be difficult at best, there are benefits in terms of regulatory consistency of adopting a pre-tax approach for the current BNE determination.

Assessing a pre-tax WACC requires making an adjustment to the cost of equity using a 'tax wedge' based on a given tax rate. For simplicity we have used the statutory tax rates in each jurisdiction:

- 12.5% for the RoI; and
- 20.0% for the UK.

B.8. Conclusion

The movements in financial markets and regulatory precedent means that our proposed cost of capital ranges for both the RoI and NI are substantially lower than for the BNE 2013 decision.

In the table below, we summarise the proposed cost of capital parameter ranges for the BNE 2016 for both the RoI and NI. The low and high estimates for the cost of equity for both NI and the RoI have been calculated using the average risk-free rate for both high and low cases.

Table B26: Cost of Capital Parameter Range for BNE 2016

	Republic of Ireland		Northern Ireland (UK)	
	Low	High	Low	High
Cost of Debt	1.00%	3.00%	0.75%	2.25%
Risk-free rate	1.00%	2.50%	0.50%	1.50%
Equity Risk Premium	4.50%	4.50%	5.00%	5.00%
Asset Beta	0.50	0.60	0.50	0.60
Debt Beta	0.10	0.10	0.10	0.10
Equity Beta	1.10	1.35	1.10	1.35
Post-tax Cost of Equity*	6.70	7.83	6.50	7.75
Taxation	12.50%	12.50%	20.00%	20.00%
Pre-tax Cost of Equity	7.66	8.94	8.13	9.69
Gearing	60.00%	60.00%	60.00%	60.00%
Pre-tax WACC	**3.66**	**5.38**	**3.70**	**5.23**
Equivalent Vanilla WACC	*3.28*	*4.93*	*3.05*	*4.45*

Source: CEPA

Note: Cost of Equity is calculated using the average risk-free rate for both high and low cases. This does not affect the mid-point but leads to a narrower range than without this average being used.

In previous BNE calculations the RAs have adopted the mid-point of our WACC ranges. Applying the mid-point to the ranges in Table B26 gives a pre-tax WACC of **4.52%** for the Republic of Ireland and **4.46%** for Northern Ireland.