REVIEW OF BNE / NET CONE FOR T-4 AUCTION

Undertaken for the Electricity Association of Ireland

15th June 2018

CONTENTS

EXECUTIVE SUMMARY

1.1 In early May 2018, the SEM Committee published a consultation document on the Best New Entrant (BNE)/ Net Cost of a New Entrant (Net CONE) supported by a study carried out by Poyry (SEM -18-025 and 18-025a). The Poyry study was completed in March 2018. The results are intended to inform decisions on the auction parameters to be defined for the T-4 capacity auction for the year 2022/23 to be conducted in March 2019.

1.2 The Electricity Association of Ireland (EAI) have asked Frontier Economics to carry out a short review of the SEM Committee's proposals.

1.3 We find that there are a number of issues of principle in the approach taken by Poyry to the choice of reference technology. Specifically:

a. Taking the absolute minimum of estimates across the technologies reviewed is incorrect;

b. the need for the "headroom" provided by the auction price cap and the risks of deterring potential investors in new capacity have not been properly considered;

c. unrealistic planning assumptions for a CCGT have been adopted. This mattered little for a hypothetical BNE plant in the SEM but is not compatible with estimates that are intended to reflect the decisions of a rational investor in the I-SEM building new plant for 2022/3. As a result, there would appear to be a significant risk that the timescale and potentially cost assumptions underpinning the CCGT reference plant are invalid;

d. Insufficient weight has been given to the uncertainties associated with the IMR and DS3 income estimates, especially for CCGTs and to the consequences that these uncertainties might have for the return on capital required by a rational investor in an CCGT in comparison to OCGT plant.

1.4 All of these considerations, would, in our view, have indicated that the right approach was to take a more realistic and certain view of Net CONE and to base it on an OCGT rather than a CCGT plant. All capacity markets in the US that we have considered use OCGT as the basis for their Net CONE estimates.

1.5 With regard to the Net CONE estimates themselves:

a. OCGT capital cost for candidate units have diverged since estimates were made for the 2016 BNE review. Poyry take the minimum value in terms of €/kW whilst recognising that market demand is increasing. A more robust approach would be to base Net CONE on an average of candidate OCGT units (excluding any outliers);

b. Interest during construction has been based on the cost of debt alone and takes no account of the cost of equity during construction;

c. We understand from discussions with EAI that electrical, gas and water connection costs are unrealistic and likely to be underestimates; and

d. Fixed costs for OCGT are distorted by the different treatment of gas transport capacity in NI which does not seem to reflect underlying network costs. This does not seem to us to be a sound basis to come to conclusions on the choice of reference technology or its location.

1.6 With regard to the IMR estimates:

a. The value for a CCGT is based on an unrealistic approach that does not appear to consider the impact of new generators joining the system in the later years of the reference plant's life or the increasing penetration of renewables. No system modelling has been carried out to assess the realism of the assumptions. We think that the IMR figure for CCGT is very likely to be an over-estimate, creating significant doubt around the overall Net CONE estimate; and

b. The estimates of IMR during periods of scarcity pricing are based on an 8 hour LOLE standard, although the SEM Committee is currently consulting on the adoption of a 3 hours standard; and

c. Even if the 3 hour standard is not adopted, the value of IMR for an OCGT in NI are over-estimated because they do not reflect the NI security standard (LOLE).

1.7 DS3 revenues for CCGT plant have also been over-estimated because:

a. for both reference technologies it is assumed that service provision is without additional cost, but it is unclear if the capital cost estimates include provision for the plant characteristics needed to supply enhanced DS3 products. Some of the DS3 revenues should be set off against these additional costs;

b. DS3 estimates rely on average figures derived by EirGrid for all existing CCGTs; and

c. There is no mention of interactions with the energy market that might lead to DS3 income being competed away.

1.8 The Poyry WACC estimates rely excessively on regulatory decisions for networks and similar assets. Insufficient weight is given to decisions in other jurisdictions on the WACC values appropriate for merchant generators in capacity markets with a similar risk profile. Within the range of values Poyry estimates, the choice of a value towards the bottom of the range is without justification, particularly given the significant uncertainties and risks of underestimates in other areas. While a full analysis is beyond our scope, we consider that the WACC estimate may be as much as 2.5 – 3.5 percentage points below the right level.

1.9 We have summarised these points in Table 1 below and given our subjective assessment of their impact on the Poyry estimate of Net CONE. Taking account of these factors would provide a more appropriate estimate of Net CONE.

Table 1 Assessment of impact of findings on Net CONE

Item	Impact
Use average EPC cost of candidate OCGTs €/kW	Medium
Use WACC to estimate cost of capital during construction	Medium
More rigorous assessment of IMR for CCGT	High
Base IMR on different LOLE	Low
Make DS3 income for CCGT consistent with load factor	Medium
Allow some incremental capital costs to provide DS3 services	Low
Align WACC more closely with other Net CONE decisions	High

Source: Frontier analysis

1.10 Underestimation of Net CONE can have serious consequences for willingness to invest and for security of supply because it is used as the basis for setting the auction price cap and as an anchor point for the demand curve. The current proposal is to set the auction price cap at 150% of Net CONE, which provides some headroom above the estimate of Net CONE. However, we estimate that, taking the Poyry numbers at face value, an investor seeking to recover capital costs for an OCGT over the 10 year duration of a reliability option might need to see a clearing price of 137% of Net CONE in order to invest. If the investor's WACC is only 0.8 percentage points greater than Poyry's estimate, the remaining headroom would be taken up.

1.11 As a result of our assessment we would recommend that:

a. a more prudent approach is taken to technology choice, which given the uncertainties and practical issues associated with CCGT technology would imply use of OCGT technology as the reference plant;

b. A significant review of the underlying estimates and calculations is needed in order to take account of the issues raised above, and avoid the potential significant consequences associated with materially under-estimating the true value of Net CONE. This applies in particular to the IMR estimates and WACC; and

c. In due course fresh thinking at the principles level is needed in relation to the right approach to estimating costs given the purpose of Net CONE and the associated auction price cap in the context of the I-SEM.

1.12 In the interests of transparency, and to allow industry participants an opportunity to fully review the analysis behind the SEM Committee's proposals, we also recommend that the SEM Committee should make Poyry's underlying calculations available for review. From the limited information available, we were unable to reproduce all of their results.

2 INTRODUCTION

2.1 In early May 2018, the SEM Committee published a consultation document on the Best New Entrant (BNE)/ Net Cost of a New Entrant (Net CONE) supported by a study carried out by Poyry (SEM -18-025 and 18-025a). The Poyry study was completed in March 2018.

2.2 The consultation document recommends the lowest cost value for Net CONE of €86/kW-derated per year corresponding to a CCGT reference plant in NI.

2.3 The results of the consultation are intended to inform decisions on the auction parameters to be defined for the T-4 capacity auction for the year 2022/23 to be conducted in March 2019. Specifically, the value of Net CONE is used:

a. as the basis for the auction price cap (currently proposed as 150% of Net CONE) and the existing capacity price cap (currently proposed as 50% of Net CONE); and

b. to anchor the sloping demand curve so that, at Net CONE, enough capacity is procured to meet the security standard.

2.4 Unlike the arrangements in the SEM, where BNE/Net CONE determined the size of the capacity payment sum, capacity payments are now the result of a competitive auction. But the value of Net CONE determines if there is sufficient "headroom" below the auction price cap to attract new entrant generators and may also directly impact on security of supply, depending on the shape of the demand curve set by the SEM Committee and the final auction clearing price.

2.5 At a high level the estimation of the cost of BNE/Net CONE involves:

a. Determining candidates for the reference technology for a BNE that an investor is likely to choose;

b. Reviewing capital and operating costs in order to assess the Gross CONE per derated kW for the reference technology;

c. Estimating the cash flows from the energy and ancillary services markets to be deducted from estimate of Gross CONE in order to give a figure for Net CONE per derated kW;

d. Determining the weighted average cost of capital (WACC) that a new entrant investor will use when deciding how much revenue will be needed from the capacity market to justify the investment; and

e. Calculating the value of Net CONE on an annual basis by combining the WACC estimates and the cost data to give a figure in € per kW/year.

2.6 The Electricity Association of Ireland (EAI) have asked Frontier Economics to carry out a short review of the SEM Committee's proposals. Our review is presented under the following headings:

a. Choice of technology;

b. Cost structure and overall cost of chosen technologies;

c. Calculation of energy infra-marginal rents;

d. Calculation of ancillary services revenues;
e. Financial parameters;
f. Calculation of BNE Net CONE; and
g. Use of net CONE in CRM in setting auction parameters and the implications.

2.7 In each case we first briefly describe the Poyry approach and then present our assessment and conclusions.

3 CHOICE OF REFERENCE TECHNOLOGY

3.1 One of the first steps in the estimate of Net CONE is choice of the reference technology.

Poyry approach

3.2 An important feature of the Poyry proposals is that, unlike previous BNE assessments, the reference technology of choice is not limited to an open cycle gas turbine (OCGT). Combined cycle technology is also analysed in detail and BNE / Net CONE values are estimated for both OCGT and CCGT plants.

3.3 Poyry notes that OCGTs were never actually built as new entrants in the SEM, in spite of being chosen as the BNE reference technology, but that a number of CCGT plants were constructed. The implication is that real investors may in practice choose to continue to build CCGT plants. After carrying out all of the analysis, Poyry concludes that a reference CCGT plant based in NI would have the lowest value of Net CONE, although the cost advantage over OCGT is small.

3.4 In the consultation document the SEM Committee says that it is of the view that the lowest value of Net CONE should represent the BNE "as it provides an appropriate expectation of a rational investor within a competitive auction process whilst being mindful of the need to protect consumers".[1]

Assessment

3.5 We discuss a number of considerations pertaining to the choice of reference technology and provide some background on practice in other markets where Net CONE has been estimated for a capacity market.

Consideration for the choice of reference technology

3.6 We discuss the following considerations:

a. The purpose of the estimate of Net CONE in the capacity market;

b. Whether past investment decisions are a guide to the future;

c. Whether the planning assumptions for a CCGT plant are realistic; and

d. The uncertainty about a Net CONE estimate based on CCGT arising from a number of different risks.

Purpose of Net CONE estimate

3.7 In the past BNE cost reviews have had a direct impact on generator revenues because the results were used to calculate the money paid in the SEM Capacity Payment Mechanism. Under I-SEM, this will no longer be the case. The auction price cap for new capacity in the first I-SEM capacity auction was set at 150% of

[1] BNE/Net CONE consultation, SEM 18-025, page 24.

Net CONE and the price cap for existing capacity at 50% of Net CONE.[2] A recent SEM Committee consultation documents proposes to use the same ratio to define the auction price cap and existing capacity price cap for the T-4 auction.[3]

3.8 The SEM Committee has argued that the purpose of the auction price cap is a safeguard against market power but, as noted in Section 1, it must also provide headroom for new capacity of any efficient technology to bid in the auction. An important reason why headroom is needed concerns the duration of the reliability options on offer. New capacity is entitled[4] to a 10 year reliability option but capacity market revenues beyond that point are uncertain. Investors may therefore seek a price for a reliability option consistent with higher revenues in the early years and accept lower, less certain revenues later. If a value of Net CONE is chosen that is too low, this could impact on the willingness to invest (either at all or with particular technologies) in a year when new capacity is needed, with implications for security of supply. We return to this point in Section 9.

3.9 The fact that Net CONE is being set for 2022/23, a year four years hence in which conditions are uncertain, might also suggest a need to provide additional headroom.

Past investment as a guide to the future

3.10 The Poyry report implies that past experience of technology preferred by investors may be a good guide to the future – CCGTs were built in the past but OCGTs were not. However, now that a number of CCGT plants have been added to the system, and with SNSP rising and thus load factors of existing CCGT falling, a rational investor might think that an OCGT plant would be the preferred choice for the I-SEM markets. This is especially so given that most of the revenue for an OCGT plant in the first 10 years could come from a reliability option if the offer is at or below the clearing price. This is not the case for a CCGT plant, which would be much more dependent on the energy markets to recover investment costs.

3.11 EirGrid's generation capacity statement makes no reference to the type of capacity that might be required in future. Poyry does not cite any system modelling work that suggests that further CCGT plants would be optimal choices given the present plant mix. In the absence of such evidence, greater emphasis has to be placed on a view of what a rational investor might do.

Planning assumptions are unrealistic

3.12 Poyry assumes that the CCGT plant is built on a greenfield coastal site (to provide easy access to cooling water) and that planning permission is given to develop on agricultural land, close to a relatively unconstrained part of the network and with ready access to an appropriate gas network connection.[5] The land area required is 80,000 m^2. Poyry notes that this reflects the assumptions adopted in previous years.

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[2] EirGrid Final Auction Information Pack for the 2018/19 T-1 capacity auction, December 2017

[3] CRM Parameters for the T-4 2022/23 capacity auction, SEM-18-028

[4] Providing it meet the investment threshold currently set at €300 per derated kW.

[5] Poyry p. 22-23

3.13 Our discussions with EAI members cast doubt on whether these assumptions are realistic for a new CCGT plant which would be available by 2022/23. We understand that achieving planning permission can be time consuming, implying that for any given site it would already need to be relatively advanced in order to avoid eating into the 4 year period after the auction, leaving insufficient time for construction in the 30 months assumed.

3.14 The assumptions made by Poyry may have sufficed in the past when the BNE was a theoretical exercise and was focused on OCGT technology, but as Poyry says, the purpose in the I-SEM is to assess what a rational investor could achieve. In this context, it would appear that there may be significant doubt as to whether practical considerations render the CCGT cost and timescale estimates invalid.

Uncertainty of IMR estimate for CCGT

3.15 Finally, any estimate of Net CONE based on a CCGT plant depends heavily on Infra Marginal Rent (IMR) and DS3 revenue estimates which are subject to significant uncertainties over the 20 year plant life assumed from 2022/23 including those relating to:

a. Demand growth;

b. The rate of penetration of renewable technologies;

c. The relative position of new CCGT plant in the merit order stack and how it changes over time – as IMR and DS3 revenues represent about half of Gross CONE, a 10 % change in these offsets will lead to a similar percentage change in Net CONE; and

d. Further regulatory interventions in the I-SEM which represents a new market design that is likely to evolve over the coming years.

3.16 The uncertainties above would have significantly less impact on an OCGT plant, that expected to see a very significant element of its costs recovered through the guaranteed 10-year capacity contract. As a result, the risk of market distortions from regulatory failure as a result of incorrect assessments of Net CONE are higher with a CCGT plant.

Reference technology in other capacity markets

3.17 We have looked at the evidence available on choice of reference technology from the capacity markets in GB, ISO New England and PJM.

3.18 The value of Net CONE in GB is set by BEIS and communicated to the Delivery Body (National Grid) responsible for the conduct of the auction. On the basis of a 2015 BEIS background document about how auction parameters are determined,[6] we understand that the reference technology adopted is a CCGT plant and that Net CONE reflects the lowest bid that a CCGT plant would make in the capacity market in the BEIS Dynamic Dispatch Model. The background document says that

6 Background on setting Capacity Market parameters, October 2015, available at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/468203/Capacity_Market_-_parameters_0810.pdf

the reference plant choice is reviewed annually although we have found no published record of such a review.

3.19 In any case, the value of Net CONE has remained at £49/kW/per year since 2014 and auction price cap is set at 150% of this value, although the clearing price determined in the auction in GB is indexed, which is not the case in the I-SEM. Our understanding is that this value is based on a much larger CCGT plant than would be appropriate for the I-SEM and uses H class turbines. [7]

3.20 ISO New England (ISO NE) reviews their capacity auction parameters every 3 years. This was last done in early 2017. A range of technologies were assessed including OCGT and CCGT. An OCGT (H Class) was chosen as the reference technology because it was expected to be the most economically efficient and is commercially available for new capacity providers.

3.21 PJM reviews their auction parameters every four years (such a review is taking place now). PJM commissioned a detailed study from Brattle which was finalised in April 2018. Brattle considered a range of technologies and evaluated Net Cone for both OCGT and CCGT options. The Brattle recommendation was to adopt CCGT as the reference technology which the analysis suggested was a significantly cheaper option, after allowing for energy and ancillary service deductions. It is also the dominant type of thermal plant on the PJM system.

3.22 In spite of this finding, PJM itself has made a preliminary recommendation to keep OCGT as the reference technology on the following grounds:

> “The fact that the CT [i.e. OCGT] receives the smallest amount of its revenue from the energy market means that its Net CONE value is the least likely to be significantly perturbed by potential changes in energy market prices. Thus, certainty is provided through the use of a peaking unit as reference resource because it minimizes the exposure to short-term energy revenue offset volatility. Also, PJM believes that maintaining the same technology type provides market stability and avoids perceived opportunistic switching to units with more favourable economics in any given year.[8]

Conclusion

3.23 The SEM Committee is proposing to use CCGT technology as the reference for Net CONE, largely on the grounds of cost minimisation. In our view this approach carries significant risks.

3.24 A percentage of the Net CONE value will be used as the T-4 auction price cap and will therefore set the headroom for bids. If this is too low there is a risk that the auction will not be technology neutral or efficient, and that CCGT technology will effectively have been indirectly chosen by the regulators. Net CONE may also impact how much capacity is procured and may therefore influence security of

[7] New capacity has been willing to accept prices below Net CONE in GB T-4 auctions but a great deal of this is embedded in the distribution network and was eligible for embedded benefits, lowering the capacity price at which investment was viable.

[8] VRR Curve Key Parameter (Quadrennial) Review, PJM Preliminary Recommendations, 24 April 2018 available at https://www.pjm.com/-/media/committees-groups/committees/mic/20180502/20180502-item-11a-pjm-quadrennial-review-preliminary-recommendations.ashx

supply (depending on the final shape of the demand curve chosen by the SEM Committee). Our view is that in these circumstances a cautious approach is indicated, not one that just focusses on the lowest cost.

3.25 A Net CONE based on a CCGT, as opposed to one based on an OCGT, depends much more on estimates of IMR and DS3 income, which are inherently uncertain, especially for a plant that will not be commissioned until 2022/23. This is especially so in the I-SEM, a new market design which is likely to change over time. Use of an OCGT reference technology reduces these risks.

3.26 In the US, both PJM and ISO New England base Net CONE on OCGT technology. The rationale adopted by PJM in their preliminary recommendation echoes the issues raised above.

3.27 Our conclusion is therefore that there is a strong rationale for choosing OCGT as the reference technology.

4 COSTS

4.1 The costs of the reference technology and candidate plant types are, of course, a key element in the estimate of Net CONE. We review both the cost of OCGT and CCGT reference options below.

4.2 EPC costs account for the 75 – 80% of the overall capital costs assessed by Poyry.[9] We first consider EPC costs for OCGT candidates and then the CCGT candidate. We also discuss the allowances for financing and interest during construction.

4.3 We have also briefly reviewed the fixed operating cost estimated by Poyry. We discuss this at the end of the section.

EPC costs for OCGT reference candidates

Poyry approach

4.4 The Poyry study evaluated the cost of four OCGT plant types on the basis of dual fuel use (gas/distillate) or distillate alone. The cheapest candidate, in terms of the specific cost per kW, a Siemens SGT5 - 2000E turbine, was chosen as the reference plant. The sources of the data are the Gas Turbine World Handbook 2016-17 and the GT PRO software library (and associated cost estimating program PEACE). The OCGT capacity at ISO conditions[10] has been adjusted for transmission peak winter conditions. Specific costs per kW have been calculated for an average lifetime capacity assuming output degradation at 2.5% per annum with gas-firing.

Assessment

4.5 We have compared the Poyry results with those obtained by CEPA/Ramboll in 2015 for the BNE 2016 study commissioned by the SEM Committee. CEPA/Ramboll adopted an Alstom turbine as the reference plant on the grounds of low specific cost. Of the four plant types considered in detail by Poyry, three were also assessed in 2015, including the Alstom (now part of General Electric) and the Siemens turbines. Table 2 below compares the EPC costs per kW for these three candidates in nominal terms from the CEPA/Ramboll study and from the Poyry study.[11]

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9 Poyry provides a detailed breakdown of capital costs in Table 34 on page 38 of their report.

10 The ISO temperature conditions is 15 ^{0}C. Gas turbines have a higher output at lower temperatures.

11 Total capital costs were revised in the 2016 BNE study in the final decision but no change was made to the EPC cost of €94.5m. The main revision was an increase in the cost for electrical connection.

Table 2 Comparison of EPC costs for candidate OCGTs in €/kW installed

	2015	2018	% change
Alstom/GE13E2	469.1	482.8	2.9%
Ansaldo AE 94.2	493.4	489.9	-0.7%
Siemens SGT5 - 2000E	506.9	461.1	-9.0%

Source: CEPA BNE Study May 2015, Poyry Cost of New Entrant Plant, March 2018. Based on average lifetime capacity.

Note that the fourth plant considered by Poyry, a GE 9E.03, was even more expensive at €500/kW than the Ansaldo unit. This was not assessed in 2015.

4.6 Poyry reports the Gas Turbine World Handbook 2016-17 as saying that orders for OCGTs are expected to rebound in 2017 following a downturn in 2016. In spite of this, the specific costs of the three candidates have diverged significantly over the three years, with only the Alstom/GE plant showing a nominal increase and the Siemens plant showing a significant nominal decrease. Looking at the figures for Siemens in greater detail shows that the total EPC cost in €m has remained virtually unchanged at €91m but the "upgrading" referred to by Poyry[12] has resulted in a 9.3% increase in the capacity under ISO conditions from 172 to 188 MW[13]. The figures presented suggest that EPC contractors/Siemens are passing all of the benefits of the increase in capacity on to buyers and, at the same time, have kept their overall costs constant in nominal terms for the last three years.

4.7 We have not had access to the sources used by Poyry but *prima facie* these results seem surprising. For this reason we think it would be helpful if more of the underlying data could be published so that the timing and number of orders that support the cost estimates, especially for the Siemens turbine, are clearer.

4.8 We have also reviewed generation cost studies carried out regularly on behalf of BEIS in GB. The last such study, published in November 2016, was supported by analysis carried out by Leigh Fisher Jacobs on the costs of thermal plants. The report looks at OCGT sizes of 100MW, 299MW, 300 MW, 400 MW and 600 MW and refers to the technology but not the manufacturer. The specific EPC costs for the 299/300 MW OCGT size is given as €472 to €492/kW[14]. which seems consistent with the CEPA/Ramboll study. The Siemens turbine retained as the reference plant by Poyry had a specific cost above this range in 2015 but is now below it, on the basis of the data in Table 2.

4.9 There is a wider point to be made about these figures given that they are now intended to reflect the result of investment decisions in the market to meet demand in four years' time. It seems to us that it is difficult to justify the assumption that a new entrant to the I-SEM market would face a cost based on an EPC contract related to the Siemens plant. If orders have indeed turned up, it is likely that the EU market will be shared between the main competing equipment suppliers. A fairer basis to reflect the actual costs of real investors might therefore be an

[12] Poyry does not explain in detail how the output capacity has been increased by Siemens.

[13] This is clearly a significant change in capacity – we assume that there is evidence that such an upgraded plant still satisfies the criterion of having run for 8000 hours at three sites

[14] The figures from the report are given in £ and have been converted back to € at the exchange rate given in the report of 1.178 €/£. The specific costs are also based on ISO conditions and not ambient conditions at the grid winter peak as used to estimate average lifetime capacity by Poyry.

average of the four candidate OCGT types that Poyry have considered, given that there are no clear outliers. This would be more realistic than relying on a snapshot taken a year or so before the investment decision in a market where prices are likely to be rising. If this were done, the effect on the specific EPC cost is as shown in Table 3 and implies an almost 5% increase in the BNE cost.

Table 3 Poyry OCGT reference versus average of candidates

Basis	€/kW
Siemens SGT5 - 2000E	461.1
Average of four candidate OCGTs	483.5
% increase over Poyry candidate	+4.85%

Source: Poyry Cost of New Entrant Report, 2018

4.10 While this section focussed on EPC costs, it should be noted that Poyry bases many other costs on a percentage of EPC costs.[15]. Any inaccuracy in the estimate of EPC costs will therefore impact many non-EPC costs.

EPC costs for CCGT reference candidate

Poyry approach

4.11 Poyry has selected the mature F class gas turbine in single shaft configuration as the basis for their CCGT candidate. This turbine type is used by three of the existing CCGT plants currently operating on the island of Ireland. Costs were estimated using GT PRO and the cost estimating program PEACE for a GE 9FB.05 machine. The Gas Turbine World Handbook 2016-17 was also consulted.

4.12 The CCGT capacity is stated at ISO conditions[16] has been adjusted for average ambient conditions. Specific costs per kW have been calculated for an average lifetime capacity assuming output degradation at 2.8% per annum. The result is an average lifetime capacity of 447.4 MW. Thermal efficiency is assumed to degrade at a rate of 1.6% per annum.

Assessment

4.13 The BNE 2016 review did not consider a CCGT option for the reference plant so there are no comparable data from this source.

4.14 The Leigh Fisher Jacobs study for BEIS, carried out in 2016, looked at the cost of CCGTs using F class and H class turbines. The F class was considered for a plant of 1400 MW comprising three separate F class turbine blocks of 466 MW but with no named equipment supplier. We would expect that these blocks would have a comparable specific cost to the plant selected by Poyry, after allowing for some economies of scale in the EPC contract (three blocks on the same site will be cheaper to engineer and procure).

4.15 As Table 4 below shows, the Leigh Fisher Jacobs study has a specific cost for EPC contract for a CCGT plant which is 6% lower than that adopted by Poyry. This

[15] For example, project development, owner's contingency, insurance, commissioning etc

[16] The ISO temperature conditions is 15 ^{0}C. Gas turbines have a higher output at lower temperatures.

seems to be intuitively plausible given the size of the plant considered in the BEIS study, albeit one using similar block sizes to that adopted by Poyry

Table 4 Comparison of EPC costs in €/kW installed

	€/kW
Poyry GE 9FB.05	595.9
Leigh Fisher Jacobs: 3 block F class CCGT totalling 1400 MW	559.5
% decrease over Poyry candidate	-6.1%

Source: Poyry Cost of New Entrant Report, 2018 and Leigh Fisher Jacobs study, Appendix F

Note: £ adjusted to € using a rate of 1.178 €/£

4.16 On this basis, we have no specific comments in relation to Poyry's estimate of CCGT EPC costs.

Other cost elements

4.17 Of the other non-EPC cost elements, we comment on interest during construction and on the siting assumptions.

Interest during construction

4.18 Poyry includes interest during construction (IDC) evaluated assuming a capital structure of 40% debt and lending rates of 2.75% and 2.5% for Ireland and NI respectively.

4.19 The estimate of IDC appears to be based on how much interest would be accrued on the debt element of financing during the construction period.[17] While this number is important for the purpose of establishing the overall financing requirement, we do not think that it properly represents the way that a private investor would consider the opportunity cost of capital over the construction period.

4.20 Poyry does not explain in detail how it has arrived at the annualised capital costs per derated kW presented in its Table 52. But we think that it is based on an annuity, at the estimated WACC, of the total capital costs, including estimated IDC, given in Table 34. If this is correct, we think that no allowance has been made for the opportunity cost of equity during the construction period. In our view the correct approach for a Net CONE calculation is to estimate the foregone cost of capital on the phased cash flows during construction using WACC and then add this to the total capital cost before they are annualised.

4.21 To gauge the impact of this point, we have estimated the cost of all capital during construction by assuming cash flow phasing based on the construction periods of 20 months and 30 months for OCGT and CCGT plants given by Poyry. The phasing of the capital expenditure we assumed is shown in Table 5 and compounding factors are shown in Table 5. Cash flows are assumed to be at the mid-point in each year so that in year 2 the cost of capital is compounded 1.5 times. These assumptions are purely illustrative and are not based on any detailed assessment of cash flows during the construction period.

[17] Poyry, p.27

Table 5 Assumed capex phasing and compounding factors

	Year -3	Year -2	Year -1
OCGT	0%	30%	70%
CCGT	20%	30%	50%
Compound factor (years)|	2.5	1.5	0.5

Source: Frontier Economics assumption

4.22 Using these assumptions we have applied Poyry's nominal WACC for Ireland of 7.31%[18] to derive an estimate of the overall cost of capital during construction and compared this to the IDC given by Poyry. The results are shown in Table 6 and illustrate the scale of the effect. As would be expected the impact is significantly greater for the CCGT plant built over a period of 30 months.

Table 6 Poyry IDC estimate vs overall cost of capital during construction

€m	Poyry IDC	Overall cost	Difference
OCGT	1.4	3.9	2.5
CCGT	5.7	30	24.3

Source: Frontier analysis

Note: Based on the construction cost in Ireland

4.23 If we have correctly interpreted the Poyry analysis, this would point to a significant underestimate of an important cost element.

Siting/location assumptions

4.24 For costing purposes, Poyry has made a number of assumptions about the location and siting of the BNE. These are that:

a. Planning permission is granted for development on agricultural land close to an unconstrained part of the transmission network. For the CCGT plant this site is on the coast;

b. The site is 5km from an existing electrical sub-station to provide access to the grid (at 110kV in the case of NI);

c. The site is under 2km from and existing gas transmission network with a pressure that does not drop below 30 bar; and

d. The site is 1km from a town water supply.

4.25 We have already noted in Section 3 that, unless the planning process is already significantly advanced, it is unrealistic to assume clearance for a new plant to be built on a greenfield, coastal site and to be commissioned for the 2022/23 capacity year.

4.26 Our discussions with EAI members also indicate that the assumptions on electric, gas and water connections are, taken together, also unrealistic. Greater distances and additional equipment (e.g. gas compressors) are likely to be involved, for both CCGT and OCGT reference technologies, for a realistic BNE plant built by a rational investor. This would increase costs beyond the levels estimated by Poyry.

[18] As we explain later in Section 7, a WACC value may be lower than the hurdle rate, the prospective return on capital, that an investor may require before deciding to build a new plant. This allows for construction cost risk and other risks that may not be fully captured in a WACC estimate.

Fixed operating costs

4.27 We have compared the Poyry estimates of fixed operating costs for OCGT plant with the estimates made in the BNE 2016 cost study. The Poyry estimate of €5.9m for an OCGT in Ireland is very similar to the final figure adopted in the 2016 study of €5.5m.

4.28 An important difference in fixed operating costs appears in the estimates for an OCGT in NI where the Poyry figure is €7.3m, compared to €4.8m in RoI, due primarily to the inclusion of €2.4m[19] for gas transportation costs (one third of the total). Gas transport costs are lower in RoI because Gas Networks Ireland makes available a daily exit capacity product, the cost of which can be recovered as a variable cost in the energy market offer price and is thus not part of fixed costs. In NI, Mutual Energy, the TSO, only offers annual gas exit capacity and this represents a fixed operating cost. The gas exit capacity products offered do not reflect any difference in the underlying costs of the respective gas networks.

4.29 In the BNE 2016 cost study, the BNE selected was an OCGT burning distillate rather than gas or distillate. The choice of fuel was due to the cost of gas transport.

4.30 It does not feel appropriate that a difference in the type of exit products offered by gas network TSOs in two neighbouring jurisdictions (with presumably similar cost structures) should have a significant impact on the value of Net CONE.

Conclusion

4.31 The EPC specific costs for three candidate OCGT manufacturers have diverged since they were last reviewed in 2015. More data on the timing and number of orders underlying the cost data is needed to justify trends which appear, prima facie, to be surprising. This suggests to us that the cost adopted by Poyry, relying on a snapshot year, may be too low.

4.32 Given this, the assumption that the BNE will be provided by one specific OCGT manufacturer is difficult to sustain. A more realistic approach might be to base the cost of BNE on an average of the costs for the three candidate gas turbines.

4.33 Poyry appears to have understated the opportunity cost of capital during the construction phase of the project, which has to be added to the capital cost stated at commissioning. This is particularly significant for the CCGT reference option which has much higher capital costs and a longer construction period.

4.34 Gas transport costs for an OCGT in NI account for one third of total fixed operating cost but are recovered separately for an OCGT in RoI. This difference is due to the way that the TSO in each jurisdiction charges for gas exit capacity. Thedifference appears to be largely artificial (rather than truly cost reflective).

[19] We understand that the NI TSO recently published draft tariffs for the next 5 years which show an increase of just under 30% compared to existing tariffs and the previous forecasts published last August. This may indicate that the NI gas tariff assumption is materially underestimated.

5 CALCULATION OF IMR

5.1 To calculate Net CONE, deductions must be made for:

a. Estimated IMR cash flow, gained from selling electricity in the forward, day ahead, intraday or balancing markets, less fuel and other associated variable costs; and

b. Revenues from the DS3 markets.

5.2 This section discusses the IMR estimates. Section 6 deals with DS3 revenues.

IMR for OCGT

Poyry approach

5.3 For the OCGT, Poyry has employed the methodology used by the SEM Committee to derive IMR for the existing BNE (for the first transitional capacity auction for 2018/19). This takes account of the fact that the reference OCGT plant is assumed to have a reliability option and only to capture IMR when Administrative Scarcity Prices (ASP) are applicable.[20] The IMR is then calculated for a 1 kW unit and a single hour as the sum of the following elements:

a. The difference between the relevant ASP and the Short Run Marginal Cost (SRMC) of the OCGT's capacity that is not covered by a reliability option (i.e. the non-derated part of the capacity based on the derating factors used for the capacity auction of December 2017) adjusted by an outage factor; plus

b. The difference between the strike price in the reliability option and the SRMC for the capacity covered by a reliability option (i.e. the de-rated capacity) adjusted by an availability factor; less

c. The reliability option difference payments (the relevant ASP less the strike price) for the capacity that is covered by a reliability option at times when the unit is on outage.

5.4 This has been done at the full ASP of €3,000/MWh for an 8 hour period, reflecting the present 8 hour Loss of Load Expectation (LOLE) standard and at an ASP of half this amount for a further four hour period when an ASP is assumed to apply but there is sufficient operating reserve remaining to avoid a full loss of load. Poyry has also considered the impact of moving to a higher maximum ASP of €11,000 based on the estimated value of lost load (VoLL).

5.5 The result is an IMR deduction of €3.6 per installed kW for the current ASP function increasing to €4.9 per installed kW if ASP is based on VoLL.[21]

Assessment

5.6 We comment on two points in relation to the data used to estimate IMR:

[20] ASP applies from the point when the TSO has insufficient operating reserve. The ASP function rises to €3000/MWh when there is no reserve left and load shedding become essential.

[21] See Poyry Tables 36 and 38 on p. 43.

a. Poyry has said, in common with previous BNE reviews, that the reference plant is located in NI where it is cheapest. However, if this is the case, the 2017 All Island Generation Capacity Statement indicates that the relevant LOLE standard is 4.9 hours and not 8 hours[22]. We note that an 8 hour standard is used for all island calculations, but this does not appear to be consistent with formally different LOLE standards; and

b. The SEM Committee is also currently consulting on the auction parameters for the T-4 auction and, in this context, has raised the possibility that the LOLE standard might be reduced to 3 hours so that Ireland is aligned to GB (with which it is interconnected) and to France and Belgium with which it is linked as part of the EU Regional Security Coordination area.

5.7 Applying the NI LOLE standard or the adoption of a new 3 hour standard would both reduce the IMR associated with gas turbines. This would cut the IMR to just over one third of the above values.

IMR for CCGT

Poyry approach

5.8 We agree with Poyry that the IMR method described above is not appropriate by itself for CCGT plant which is expected to operate at significantly higher load factors than peaking plant. It needs to be complemented with an estimate of IMR outside periods when ASPs apply.

5.9 Our understanding of the approach that Poyry has adopted for a CCGT reference plant is as follows:

a. The plant is assumed to have a load factor of 75% in 2022/23 falling to 65% after 10 years (the duration of the reliability option contract);

b. The SRMC difference between a new CCGT with an efficiency of 52.1% and a "generic" CCGT with an efficiency of 48% has been assessed over the 20 year period using projections of gas and carbon prices published by BEIS in 2017 which cover the period to 2040. The idea is that, outside the periods of ASP, the wholesale price will be linked to the costs of a generic CCGT; and

c. An uplift has been added to this indicator of wholesale prices to reflect the recovery of quasi-fixed cost such as start-up and no load. Poyry says that the uplift averaged €6.3/MWh in 2016 but they expect this to be lower in the I-SEM and have taken only 70% of this amount.

d. The IMR rent per unit of capacity outside ASP periods can then be estimated by subtracting the cost of production for a new CCGT from the projected wholesale price and multiplying this difference by production based on the assumed load factor. The estimate is then completed using a similar approach to that adopted for OCGTs during ASP periods.

5.10 Poyry reports that the IMR per MWh outside ASP periods rises from €7.4 to €10/MWh of production over the first 10 years. This translates into an overall IMR

[22] All Island Generation Capacity Statement, Appendix 3.

of €48/kW in 2022/23 rising to €57/kW installed in 2031/32. In the second decade of the plant's life, the 2031/32 IMR is assumed to decrease by 5% per year.

Assessment

5.11 Although this methodology is proposed, to quote Poyry, as "a simple approach that can develop the required level of insight" it is in practice not very transparent for three main reasons:

a. The main focus is on the first 10 years of plant operation with subsequent years being based on the a gradual decline of the position reached in 2031;

b. The relevance or source of some of the data used is difficult to understand. For example, Poyry only reports wholesale price uplift figures for a single year, 2016 under the SEM, and it is not clear on what basis uplift is assumed to average 70% of this value under the I-SEM. The BEIS 2017 projections cited by Poyry only cover fossil fuels and do not include data for carbon so the source of the price of carbon given in Poyry's Table 38 is unclear. Later BEIS publications from 2018 give different carbon values for policy appraisal but these are informed by the Carbon Price Floor scheme which only applies in GB; and

c. Poyry never explains how they have transformed the 20 year annual projections described above into the single IMR figure for the CCGT reference plant which is needed to derive Net CONE.

5.12 We also have the following more fundamental concerns about the simplistic approach followed:

a. Poyry does not seem to have taken into account that a new CCGT plant entering service in 2022/23 is likely to itself be displaced by newer, CCGT plants (e.g. using the H class turbine), shifting the BNE reference CCGT down the merit order. We note that EirGrid's study of Tomorrow's Energy Scenarios (TES) projected some net increases in gas-fired generation capacity in all scenarios, albeit towards the back end of the projection period (2020-2040);[23]

b. No explicit assumption has been made on the penetration of renewable energy sources (RES) of generation, especially wind power, which will continue to have dispatch priority. Studies carried out for DCCAE by CEPA on a new EU compliant RES support scheme assume that the SNSP limit will be raised from the current 60% to 75% from 2020 and that a baseline RES target of 40% of electricity consumption is adopted for 2030.[24] The TES study, which looks out to 2040, suggests RES as a percentage of consumption will fall in the range 47% to 75% by this year, depending on the scenario; and

c. The uplift to recover cycling costs is assumed to raise the wholesale price but not to have any impact on the reference CCGT plant. In practice, as its load factor falls, it too will have cycling costs.

[23] TES, EirGrid, 2017, p 46

[24] Economic Analysis to Underpin a new RES support scheme, CEPA on behalf of DCAEE, May 2017

5.13 Both of the above mean that the levels of IMR per MWh of production and the load factors of the reference CCGT plant may be significantly lower than those Poyry has projected.

5.14 It therefore appears that Poyry has adopted a simplified approach which is neither transparent, nor potentially very accurate. A more rigorous approach would have involved simulations of the power system using a planning model. This would have provided a better basis for judgements about load factors, especially on a relatively small power system.

5.15 That said, the level of IMR would still have depended on many assumptions, including fuel and carbon prices, interconnectors, RES capacity and costs of new plant. Therefore, perhaps the key message, echoing the quote from PJM in Section 3, is that is that the uncertainty of the IMR estimate for a CCGT plant is an argument for choosing an OCGT reference, for which IMR is much less significant, as the basis for Net CONE.

Conclusion

5.16 The IMR estimates for OCGT may have been over-estimated because they are based on an existing security standard for Ireland. In particular, adoption of a new standard of 3 hours, as raised in a recent consultation by the SEM Committee, would lead to a number that is 40-60% of the amount estimated by Poyry.

5.17 We think it very likely that Poyry has overestimated IMR for CCGT plant, mainly because the load factors assumed appear to be too optimistic. A lower estimate of IMR would favour selection of OCGT as the reference technology, as we show in Section 8.

5.18 The estimates for the IMR of CCGT plants (outside ASP periods) highlight the importance of a range of assumptions about the development of the power system and of gas and carbon prices over the period to 2042 in the calculation. IMR is a significant factor in the Net CONE calculation for a CCGT reference plant but is inherently very uncertain. This is a further reason to use OCGT as the reference technology, as in the case of the capacity markets in the US. PJM has explicitly acknowledged this point.

6 CALCULATION OF DS3 REVENUES

6.1 Poyry's calculation of BNE/Net CONE includes a deduction for DS3/ancillary services revenues in addition to IMR from the energy market.

Poyry approach

6.2 To estimate the scale of the deduction, Poyry has relied on work carried out by EirGrid for the determination of DS3 Enduring Tariffs and associated scalars. The Eirgrid study estimated the average DS3 revenue per MW for each of nine technologies (including OCGT peakers and CCGTs) across the entire installed capacity for that technology.[25] Separate figures were given for enhanced and new providers (as conventional plant is increasingly displaced from the system). Poyry has taken the average of the figures for enhanced and new providers.

6.3 This results in a deduction for DS3 revenues of €14.6/kW installed for OCGT and €7.7/kW installed for CCGT for 2017.

6.4 With relation to evolution of DS3 revenues, Poyry points to the expenditure cap of €235m set by the SEM Committee for 2020.[26] They say that they understand that that this expenditure cap will not be increased to reflect inflation after 2019/20 and on that basis assume that DS3 revenues will remain at the same level in nominal terms.

Assessment

6.5 It is not possible to evaluate in detail how EirGrid has arrived at the revenue figures for OCGT and CCGT because its report does not provide much detail and only summarises the results of the modelling work involved. However, there are a number of reasons to think that taking EirGrid's figures as the basis for DS3 revenues could result in an overestimate of the benefit of DS3 revenues:

a. The reference CCGT plant may earn less than the average figures reported by EirGrid;

b. Interactions between the energy and ancillary services markets may mean that the overall benefit is not the sum of separately estimated IMR and DS3 revenues;

c. The EirGrid work was published in July 2017 and takes account of the impact of scalars. This is before the SEM Committee decision of October 2017 that scalars would not be applied to DS3 products provided by constrained plants.[27] This is relevant to the applicability of the estimates to periods later in the life of CCGT or OCGT plant, when they might be constrained on;

[25] Consultation on DS3 System Services Enduring Tariffs, EirGrid, 4 July 2017, Figure 13.

[26] This figures comes from the Information Paper on the DS3 System Services Future Programme Approach - SEM 17-07, and is the end point of a glide patch increasing expenditure on system services to accommodate a higher SNSP.

[27] DS3 System Services Tariffs and Scalars SEM Committee Decision SEM-17-080, 24 October 2017.

d. The impact of the performance scalar will prompt investors to discount ancillary service revenues when taking investment decisions on BNE reference plants; and

e. The enhanced capabilities required to provide the DS3 products on a system with higher levels of SNSP may require incremental investment for both OCGT and CCGT plants

6.6 We now expand on each of these points.

Reference CCGT may earn less DS3 revenues than average CCGT

6.7 In relation to the CCGT estimate, the Eirgrid figure is clearly stated as an average for the entire portfolio of this technology. This will include some older plants, described by Poyry in the context of the IMR estimates as "generic" CCGTs. If the reference CCGT will operate at the high load factors that Poyry has claimed, it is less likely it would be able to earn average DS3 revenues, although this will depend on the system conditions.[28] Lower merit CCGTs will be in a better position to provide reserve and similar services and we would expect that the average figure given by EirGrid is based on higher DS3 revenues for older plant and lower revenues for new plant. This will change over time as new CCGTs enter the system but the lifetime average, taking account of discounting, would still be lower for the proposed reference plant.

6.8 The above considerations would not apply to a new OCGT peaker which is expected to have a very low load factor.

Impact of energy/DS3 interactions

6.9 There is also a potential interaction between DS3 revenues and offers by reference generators in the balancing market. The DS3 deduction is implicitly assumed to be independent of IMR obtained in the energy/balancing market. However, in practice, generators operate simultaneously in both markets and, depending on the position of plant in the merit order, some of the benefits of DS3 revenues may be competed away in the form of lower offers in the balancing market.[29] The Balancing Market Principles Code of Practice explicitly provides for generators to adjust their offers, up or down, to take account of their position in the DS3 market.[30] IMR and DS3 revenues may not therefore be independent. Simple addition of the two may exaggerate the benefits.

Impact of the performance scalar

6.10 EirGrid has already introduced a performance scalar in the interim arrangements and this will be continued in the enduring arrangements. The scalar will be 1 when plant meets performance criteria but less than 1 when it does not do so. EirGrid has indicated that the modelling of expenditure on DS3 services, and therefore

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[28] For example, if SNSP is high, all required thermal plant may be running at close to minimum generation and under these conditions older plant might have little advantage over newer plant.

[29] For example, a CCGT running at zero/negative spark spread overnight chooses to lower its offer price below its breakeven cost of generation in order to capture some potential DS3 revenues. If it decided to cycle, it would avoid the loss on energy, but incur a loss on DS3 and the start costs of the following day.

[30] BMPCoP, SEM 17-049, para 38

presumably plant revenues, was based on a scalar of 1. [31] In practice EirGrid says that scalars of less than 1 will apply for many providers.

6.11 The performance scalar framework is thus asymmetric so that the average level of the scalar, as seen through the eyes of a potential investor in BNE reference plant, is already less than 1 due to the risk of some non-performance. In practice, a projection of DS3 revenues for an investment appraisal may discount the average revenues as foreseen by EirGrid more heavily given the asymmetric nature of the risk.

Enhanced capabilities may come at additional cost

6.12 Finally, there is also a more fundamental argument about the deduction of DS3 revenues to obtain Net CONE. The name “ancillary services” implies that these services are ancillary to normal operation of the plant and are thus provided at no additional cost. Unlike the IMR estimate, there is no cost subtracted from DS3 revenues in order to obtain the amount to be deducted from CONE.

6.13 This is a reflection of the past when ancillary service provision was within the normal capability of conventional plant. However, as the work programme on DS3 carried out by EirGrid makes clear, the need to work at higher levels of SNSP requires enhanced services such as faster response. These can require investment in flexibility in order to achieve the enhanced capability required. The efficiency characteristics of a plant may also be optimised to provide certain combinations of DS3 and energy services and then may not be optimal for baseload operation.

6.14 Poyry’s discussion of the cost of the reference technologies gives no indication of whether the data used reflects these enhanced capabilities. If it does not, then at least part of the DS3 revenues need to be considered as a return on the additional investment in flexibility rather than a costless source of revenue for any new entrant.

Conclusion

6.15 We find that DS3 revenues for a reference CCGT plant may have been exaggerated:

a. it is based on an EirGrid assessment for an average CCGT, rather than a newer plant;

b. The estimates for DS3 revenues from both CCGT and OCGT take no account of interactions with the estimate of IMR for the energy market or the impact of the new performance scalar.

c. It is not clear whether the assessed capital costs take account of the potential need to incur cost to enable the plant to provide new, enhanced DS3 products.

[31] DS3 System Services Tariffs for Regulated Arrangements Recommendations Paper, EirGrid, October 2017, p. 35

7 FINANCIAL PARAMETERS

7.1 BNE / Net CONE is expressed as a levelised cost in term of € per derated kW per year. This requires an estimate of the weighted average cost of capital (WACC), which is equivalent to a discount rate, in order to annualise the costs. WACC is also used to estimate the average value of IMR and DS3 revenues over the life of the BNE plant.

Poyry approach

7.2 Poyry uses the Capital Asset Pricing Model to estimate WACC, drawing on a number of sources to obtain the financial parameters required. Many of the sources used concern decisions taken for network regulation and other regulated assets. Poyry recognises that the cost of capital adopted for regulated assets is not directly comparable with the cost of capital that a merchant generator making a decision to invest in a new entrant plant would seek. They do give some comparative figures for WACC in other jurisdictions where Net CONE is assessed for the purpose of capacity markets.

7.3 WACC is estimated as a real cost of capital but is then converted to nominal terms because the strike price determined in a capacity auction is not indexed. Its value is therefore eroded by inflation over time in the case of a multi-year reliability option. Poyry assumes a long-term inflation rate of 2% for this purpose.

7.4 Pre-tax WACC values are calculated and are used to calculate the levelised costs but post tax WACC values are also given for comparison with rates adopted elsewhere. Corporate tax rates are those which will apply in each jurisdiction from 2020.

Risk free rate

7.5 Poyry has considered evidence of the real yield on bonds in UK and Ireland and evidence from recent regulatory decisions in both jurisdictions. They propose the following ranges as a basis for consideration:

a. NI – 1.25% to 2%

b. RoI – 1.5% to 2.5%

7.6 For both jurisdictions Poyry has then selected the lower bound of the range as the basis for WACC.

Equity risk premium

7.7 For the equity risk premium, Poyry draws on evidence from:

a. The DMS database of real returns on major asset classes maintained by Credit Suisse;

b. Data on equity risk premiums analysed and published by Aswath Damodaran at the Stern School of Business, New York; and

c. Regulatory precedents in both jurisdictions.

7.8 The recommendation is 4.75% for RoI and 5.25% for NI, which Poyry says is in line with recent regulatory decisions.

Gearing

7.9 On gearing (i.e. the proportion of debt in total capital) Poyry considers:

a. Evidence of the actual gearing of vertically integrated electricity companies that typically fall in the range 30 - 40%;

b. Recent decisions for regulated assets in each jurisdiction:

   i. RoI 30-60%

   ii. UK 55 – 65%

c. The levels used in the PJM and ISO-NE decisions on Net CONE of 65% and 60% respectively; and

d. The 2016 BNE decision in which the originally proposed gearing of 60% was reduced to 30% following consultation.

7.10 Weighing the evidence, Poyry says that lower levels of gearing are indicated for competitive segments and recommends a figure of 40%.

Beta

7.11 Poyry considers the following evidence on equity beta and asset beta:

a. 5 year monthly equity betas for quoted companies available from Thomson Reuters that fall in the range 0.37 to 1.26;

b. Aswath Damodoran who recommends an asset beta of 0.63 for European power companies, equivalent to an equity beta of 1 at 40% gearing; and

c. Recent decisions for regulated assets in both jurisdictions.

7.12 Poyry recommends an equity beta range of 0.76 to 1, in which the lower end reflects regulatory decisions and the upper end reflects the figure from Aswath Damodoran. They recommend taking the average value of 0.88 for the WACC estimate.

Debt premium

7.13 The debt premium is the additional return that lenders demand over the risk free rate. Poyry has considered the following evidence:

a. Spreads over the nominal yield on gilts for a number of utilities which have quoted bonds – all with a BBB+ or better credit rating – that range from 0.36% to 4.37%;

b. Figures published by the CMA for the period 2007 to 2014 which range from 1.5% to 3% for generation; and

c. Data from a range of recent regulatory decisions in both jurisdictions.

7.14 Poyry concludes with figures for the real costs of debt, after adding the risk free rate. In Table 7 below we show the debt premium range that is implied and the final recommended figure for the real cost of debt. The recommended figure is close to the lower end of the range.

Table 7 Poyry recommendation on the real cost of debt

	RFR	Debt premium	Debt cost	Recommended
RoI	1.5%	1 – 2.5%	2.5 – 4%	2.75%
NI	1.25%	1 – 1.75%	2.25 – 3%	2.5%

Source: Poyry and Frontier analysis

Poyry WACC recommendations

7.15 Poyry summarises the range of values for the input parameters, their recommended values and the pre-tax WACC values that flow them. Table 8 below summarises their results for nominal WACC i.e. after allowing for a 2% long-term inflation forecast.

Table 8 Poyry pre-tax nominal WACC values

	Lower	High	Recommended
RoI	6.59%	8.69%	7.09%
NI	6.78%	8.69%	7.31%

Source: Poyry Table 51

7.16 Poyry concludes by noting that its WACC estimates are "somewhat" lower than the WACC estimates adopted in the calculation of Net CONE in GB and in the calculation of the same parameter for the ISO-NE and PJM capacity markets. The comparative figures quoted are set out below. We have made adjustments to put them on the same basis as the pre-tax nominal WACC for calculating Net CONE in the I-SEM:

a. GB capacity market – a real pre-tax "hurdle rate" (very similar to WACC as used by Poyry) of 7.5%. No source is given by Poyry but this appears to be a figure from 2013. BEIS's 2016 generation cost study uses a 7.8% real pre-tax hurdle rate for CCGT and OCGT plants, at the bottom of the range proposed by a NERA analysis.[32] Like Poyry, BEIS assume a 2% long term inflation rate so that the equivalent nominal WACC is 9.9%;

b. ISO-NE capacity market – the estimate of Net CONE made in January 2017 uses a nominal post tax WACC of 8.1%. The equivalent pre-tax nominal WACC figure, allowing for the December 2017 changes in the US tax regime, would be 12.3%;[33] and

c. PJM – Poyry says a post tax nominal WACC of 8% was used by PJM but this figure relates to 2014. The recent 2018 review of Net CONE uses a post tax WACC of 7.5%.[34] The equivalent pre-tax nominal WACC figure is 10.6%, again allowing for changes in federal taxes.

[32] BEIS Generation Cost Report, 2016, page 61. Note that revenues are indexed for inflation so real rates are appropriate. The figures are based on research by NERA's study of electricity generation cost and hurdle rates, July 2015. This suggested a range for gas-fired plant of 7.8 – 11.8% and a reference point of 9.8% fin pre-tax real terms.

[33] Assumes an overall tax rate (federal + state) of 29.5%. Tax rates in specific states differ slightly. In our assessment later in this section we restate the US WACC data at the Irish rate of corporate tax.

[34] PJM Cost of New Entry, Brattle, April 2018, Table 16, p. 37

7.17 In the next section we have included a table that presents these rates after removing the impact of higher US taxes.

Assessment

7.18 In our assessment we:

a. First review the comparators Poyry has presented for the value of WACC (or the hurdle rate) used in the Net CONE calculation for other capacity markets;

b. Second consider Poyry's recommendation within the range of WACC estimates that they have derived; and

c. Third comment on the use of the same value of WACC for OCGT and CCGT reference plants.

Review of WACC estimates used in other Net CONE decisions

7.19 We have reviewed the WACC values that Poyry mentions have been used in estimates of Net CONE in other jurisdictions, all of which are significantly higher than the value Poyry recommend.

Estimates derived for the GB capacity market

7.20 The hurdle rates used by BEIS were based on extensive work carried out by NERA.[35] Rates for renewable and non-renewable technologies were assessed.

7.21 NERA starts by making the point that the hurdle rate is distinct from WACC. It is the return that investors will look for in a financial project appraisal before deciding to invest in new generation. A financial appraisal is forward-looking. Estimates of WACC depends largely on current and historic data.

7.22 They point out that the CAPM has some features that make it unsuitable as the only basis on which to derive hurdle rates. The main concerns expressed are that:

a. It assumes a symmetric distribution of returns, with equal exposure to upside and downside risks; and

b. It does not take account of the resolution of uncertainty over time, known as real option value.

7.23 Problems arise because some of the individual risks in power generation projects are asymmetric and have a large downside risk with little upside. The main risks concerned are:

a. Construction cost risk where overruns are more likely than cost savings;

b. Policy and regulatory risk once an investment is sunk – this is asymmetric because power generation investments cannot be liquidated and once made there may be little to deter changes in the regulatory rules in the short term; and

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[35] Electricity Generation Costs and Hurdle Rates, NERA, July 2015 published by BEIS.

c. Technology maturity risk caused by new advances which cannot be incorporated into existing long-term power generation assets. The trend towards higher thermal efficiency of gas turbines is one example.

7.24 The issues raised by use of the CAPM to derive hurdle rates led NERA to rely heavily on survey data collected from the investor community. The results were then sense-checked using an extended CAPM framework and a range of other market data.

7.25 This approach largely explains the higher real pre-tax hurdle rate range of 7.8-11.8% and a reference rate of 9.8% (9.9% to 14% and a reference of 12% in nominal terms) that was proposed by NERA for gas-fired plant.[36] It is also important to keep in mind that in the GB capacity market investors do not bear inflation risk. BEIS adopted a figure at the lower bound of the range for its 2016 generation cost study.

7.26 When NERA derived hurdle rates for gas-fired plant, corporate tax rates were 20% so we have restated their rates on the basis of the same 17% tax rate used by Poyry for 2020 and compared the results to the Poyry WACC for NI in Table 9. All data are pre-tax nominal. On this basis, the Poyry rate for NI is 2.3% below the rate adopted by BEIS and 4.4% below the NERA reference rate.

Table 9 Comparison of NERA/BEIS UK WACC at 2020 UK tax rate

	At 20% tax rate	At 17% tax rate	Difference
Poyry		7.31%	
NERA - Low / BEIS	9.9%	9.6%	2.3%
NERA Reference	12%	11.7%	4.4%
NERA High	14%	13.7%	6.4%

Source: *Poyry, NERA – Electricity Generation Costs and Hurdle rates, July 2015*

Note: *As hurdle rates do not have separate equity and debt components we have reduced the hurdle rates by 0.3% which would be the change in WACC using ISO NE parameters if tax rates were reduced from 20% to 17%.*

Estimates from the US market

7.27 We have reviewed ISO New England's FERC filing on Net CONE produced in January 2017[37] as well as the more recent Brattle Study for PJM of April 2018. Both studies base their WACC estimates on CAPM rather than any assessment of hurdle rates but the focus of benchmarks is very much on generation companies. Evidence from regulated asset decisions is not a significant input. The key differences in comparison to the results reported by Poyry are:

a. Estimates of the equity risk premium are based on projected (not historic) market returns and are significantly higher than the figures of 5.7% - 5.8% (in real terms) adopted by Poyry. Nominal returns on equity, based on projected

[36] Another point of comparison is the provided by the 2015-16 investigation by the Competition And Market Authority (CMA) into the GB energy market. The CMA estimate a nominal pre-tax WACC range of 8.2-10% for generators. WACC rates were used to assess competitive benchmark revenues i.e. the investigation was not looking at hurdle rates for new investment.

[37] ISO New England Inc.; Filing of CONE and ORTP Updates Docket No. ER17- -000, January 2017

returns, are 13.4% for ISO NE and for PJM 12.8%. The higher returns are also due to the impact of the higher gearing (see below) on leveraged beta value;[38]

b. The nominal cost of debt is higher, in part because the bonds issued by merchant generators in the US have a lower credit rating (B - BBB) than bonds considered by Poyry. US interest rates are also higher than those in the EU. ISO NE uses rates of 7.75% and PJM 6.5% for debt in nominal terms. These rates compared to 2.5 – 2.75% adopted by Poyry (in real terms);

c. The higher cost of equity is partially offset in the WACC calculation by the use of higher gearing: 60% - 65% in the US examples compared to 40% in the Poyry study; and

d. US tax rates, even after the changes in the tax regime at the end of 2017, are still significantly higher than those assumed to apply after 2020 by Poyry. This increases the pre-tax WACC.

7.28 To make a comparison with Poyry's estimate for Ireland, we have restated the results from PJM and ISO NE at the lower Irish tax rate of 12.5% (we have not adjusted for any other differences, including for example debt costs). The results are shown in in Table 10. On average the US pre-tax nominal WACC estimates are 3% higher than those estimated by Poyry at the same tax rate.

Table 10 Comparison of US WACC estimates at Irish tax rate

	At US Tax Rates	At 12.5% tax rate	US less Poyry
Poyry		7.1%	
NE ISO	12.3%	10.8%	3.7%
PJM	10.6%	9.3%	2.2%

Source: Poyry report; Brattle Report for PJM,April 2018, ISO-NE FERC filing, Jan 2017

7.29 As in the case of NERA's hurdle rates for GB, both the PJM and ISO-NE studies use the same WACC values for OCGT and CCGTs but choose OCGT as the reference technology.

7.30 A final point is that the US WACC data used to calculate Net CONE is, in our view, more relevant to the I-SEM than would be value for a network business on the island of Ireland. The jurisdiction is different but the risk profile is much more similar to that for the estimation of Net CONE for the I-SEM than the risks faced by regulated business on the island of Ireland.

Choice of recommended WACC in the range of estimates

7.31 Table 8 above shows that Poyry has recommended a figure for pre-tax WACC that lies at the bottom end of their range. The recommended figure is a consequence of the separate recommendations from the ranges derived for each input parameter. But it is still helpful to assess the implied weighting given to the low and high WACC values in the recommended figure. The overall range (low to high) is 2 percentage points for Ireland and 1.8 percentage points for NI. The recommended values lie only half a percentage point above the minimum. This is

[38] Equity return is the "risk free rate" plus equity beta times the market equity risk premium, where the value of beta is adjusted for gearing.

equivalent to giving a weighting of 75% to the lower figure and only 25% to the higher figure.

7.32 Poyry gives no reason to justify such an implicit weighting. If anything, the significant reliance on regulated comparators to inform the CAPM model inputs in Poyry's analysis is likely to unduly bias estimates downwards, there would be a strong rationale to go towards the top end of the range in order to, at least in part, offset the structural downward bias. Even then, the bias may not be completely offset.

Use of the same WACC for OCGT and CCGT

7.33 Although neither BEIS nor the US examples differentiate hurdle rates or WACC between OCGT and CCGT plants, our view is that a higher rate of return is likely to be sought by real investors in new CCGT plants. This is due to the risks to which they are exposed for recovery of capital costs, notably in relation to the size of the projected IMR. For this reason, we think that a WACC estimate towards the top end of the range of values would be appropriate – see our conclusions below.

7.34 As explained in Section 5 this depends on both the position of the plant in the merit order as well as gas and carbon prices. In contrast, a new OCGT plant can recover most of its lower capital costs (potentially all if the clearing price is high enough) during the 10 year duration of the reliability option awarded in a T - 4 auction.

7.35 This is also supported by the CAPM theory. IMR depends on demand for electricity, technology trends and fuel prices all of which have some systemic characteristics. The associated risks cannot be fully addressed by diversification.

Conclusion on WACC

7.36 In our view Poyry appears to have materially under-estimated nominal pre-tax WACC for the purpose of new generation investment. They have relied too heavily on recent regulatory decisions for utility networks and similar regulated assets with a very different risk profile to those faced by merchant generators.

7.37 Poyry themselves recognise that their proposed WACC rates are much lower than those used in other jurisdictions for the purpose of estimating Net CONE.

7.38 The same WACC rates are applied to estimate Net CONE on the basis of OCGT or CCGT reference technologies. We think that real investors would demand higher return for investing in CCGT plant given the greater risk associated with capital cost recovery.

7.39 A full analysis to re-estimate WACC is outside the scope of this review but we think that, based on Table 11 below, the under-estimate could be of the order of 2.5 – 3.5 percentage points, with the higher figure applicable to CCGT technology.

Table 11 Poyry nominal pre- tax WACC v other estimates (tax adjusted)

	RoI	NI
Poyry (2018)	7.1%	7.3%
NERA low / BEIS (2016)		9.6%
ISO – NE (2017)	10.8%	
PJM (2018)	9.3%	

Source: Poyry, Frontier Table 9, Table 10.

8 CALCULATION OF BNE NET CONE

8.1 We now review how the cost data and the WACC estimates have been combined in order to estimate Net CONE.

Poyry Approach

8.2 Poyry has first taken the capital and operating cost data expressed in €m and divided by the average lifetime capacity for each reference plant option. The average lifetime capacity is adjusted for the derating factors applicable to generating units of the relevant sizes, as set out in the Auction Information Pack for the first CRM auction held in December 2017

8.3 Poyry has then:

a. Calculated Gross CONE per kW of derated capacity by annualising the capital costs over a 20 year plant life as an annuity at the estimated WACC and added annual operating costs; and

b. Deducted the projected IMR and DS3 revenues to obtain Net CONE. As the IMR and DS3 revenues may vary from year to year over the life of the plant, a discounted present value of the projection has been calculated and the result annualised using an annuity to provide a single average figure, again using the WACC estimates.

8.4 Poyry has made these calculations on three different bases:

a. in real 2017 money using the real pre-tax WACC estimate (Poyry Tables 52 for Gross CONE and Table 54 for Net CONE);

b. in real 2022 money using the real pre-tax WACC and adjusting for inflation using a long-term rate of 2% for both RoI and NI (Poyry Table 55 for Net CONE); and

c. in nominal money using the nominal pre-tax WACC estimate with the projections of operating costs, IMR and DS3 revenues also adjusted for inflation (Poyry Tables 53 for Gross CONE and Table 56 for Net CONE).

8.5 Poyry concludes that because the strike price in the I-SEM reliability option is not indexed for inflation (i.e. it remains unchanged in nominal terms over duration of the option contract), the correct basis for Net CONE is that based on nominal prices and pre-tax nominal WACC.

Assessment

8.6 We agree with Poyry that, since the strike price determined from the CRM auction clearing price is not indexed, the correct basis for Net CONE is one determined in nominal prices using the pre-tax nominal WACC. This approach effectively compensates an investor for inflation by providing a higher return on capital.[39]

[39] This is in contrast to the GB capacity market where capacity agreement prices are indexed and Net CONE is determined using pre-tax real estimates of WACC.

8.7 Turning to Poyry's results, we have reproduced and merged Poyry Tables 53 and 56 below for ease of reference as Table 12. These present the data in nominal prices using nominal WACC.

Table 12 Gross and Net CONE in nominal money

€/kW derated	Ireland			Northern Ireland		
Reference technology	OCGT	OCGT	CCGT	OCGT	OCGT	CCGT
Fuel	Dist	Dual	Dual	Dist	Dual	Dual
Annualised capex	71.9	70.6	90	72.5	71.7	91.3
Fixed Op cost	43.5	42.4	95.5	35.9	52.1	84.3
Gross CONE	115.5	113	185.5	108.4	123.8	175.7
IMR	-4.0	-4.0	-80.8	-4.0	-4.0	-80.8
DS3 income	-16.1	-16.1	-8.8	-16.1	-16.1	-8.8
Net CONE	95.4	93.0	95.9	88.4	103.8	86.0

Source: Poyry Tables 53 and 56

8.8 We note that Gross CONE is significantly higher for the CCGT reference technology than for OCGT but after allowing for IMR and DS3 revenues, the Net CONE figures are much closer. This highlights again the sensitivity of the results to assumptions regarding IMR and DS3, and suggests that the SEM Committee should be very careful in making a BNE technology choice and cost estimate on the basis of such uncertain parameter estimates.

8.9 The calculations described above are complex and Poyry's description, while sufficient to communicate the approach adopted, does not contain a lot of detail. We have nevertheless tried to reproduce the numbers in their tables where the detail seems reasonably clear. The main points that emerge are that:

a. We can reproduce their annualised capital cost and fixed operating cost numbers, in 2017 money, based on real WACC;

b. Using nominal WACC to annualise capital costs, we obtain a number that implies a total inflation adjustment to 2022 of 9.3%. This is slightly less than 5 years at 2% inflation;

c. Our calculation of fixed operating costs for Gross CONE in nominal money is higher than Poyry by €2/kW derated for OCGT and €5/kW derated for CCGT. This may be explained by the way inflation has been treated or the timing of cash flows;

d. Our calculation of the average DS3 revenue offset is very close to Poyry for the nominal money;

e. There is insufficient information to attempt to reproduce the IMR figure.

8.10 We hesitate to conclude anything very concrete from these results except that it would be helpful if the SEM Committee could also publish Poyry's working papers in the interest of transparency. On the basis of the description in the report, it is possible that the lifetime average figure for fixed operating costs could be an under-estimate.

Conclusions

8.11 We agree with Poyry that a calculation of Gross CONE with nominal money at a nominal WACC is the correct basis given the characteristics of the reliability option.

8.12 The results highlight the extent to which uncertain estimates of IMR and DS3 revenues are ultimately driving the technology choice and BNE estimate.

8.13 In the interest of transparency, we suggest that the SEM Committee should also publish Poyry's working papers showing the details of the Net CONE calculations.

9 USE OF NET CONE IN THE CRM

9.1 The value for Net CONE informs decisions on the following parameters used in the CRM:

a. The auction price cap for which the SEM Committee propose a value equal to 150% of Net CONE – this provides headroom for investors in new generation capacity;

b. The existing capacity price cap for which a value of 50% of net CONE is proposed; and

c. The new capacity investment threshold for which the SEM Committee propose a value of €300 per derated kW.

9.2 The value of Net CONE also serves as an anchor for the sloping demand curve.

9.3 In this section we briefly explore the implications of underestimating the value of Net CONE in terms of headroom and the relationship between capacity procured and security of supply.

Headroom

9.4 A BNE investor will recognise that after expiry of the 10 year reliability option, capacity market prices are uncertain. An investor might therefore seek to recover all the capital costs of an OCGT in this 10 year period and assume that they will only recover Net Going Forward Costs (NGFC)[40] in subsequent years.

9.5 As a check on the headroom provided by the auction price cap, we have therefore used the Poyry data for an OCGT in RoI to see what clearing price, in excess of Net CONE, such a risk averse investor would require in order to meet their objective. Our calculation[41] indicates that a price of 138% of Net CONE would be sufficient, provided Poyry's estimates are realistic.

9.6 If Net CONE has been underestimated, for example, due to the value of WACC employed (7.1% in RoI according to Poyry) or because the capital or operating costs are lower than those which an investor thinks are correct, the remaining headroom could be quickly used up and investors could be deterred. We estimate that the investors' WACC need only be 7.9% for a bid at 150% of Net CONE (as estimated by Poyry) to be required to recover the capital cost of an OCGT in 10 years.[42]

[40] NGFC is fixed operating costs less IMR and DS3 revenues.

[41] We assumed each element of Net CONE in nominal money remains the same in nominal terms for 20 years. We calculated the present value of the capex and then annuitized over 10 years, both using nominal WACC. We then added fixed operating costs less IMR and DS3 revenues and compared to the BNE price.

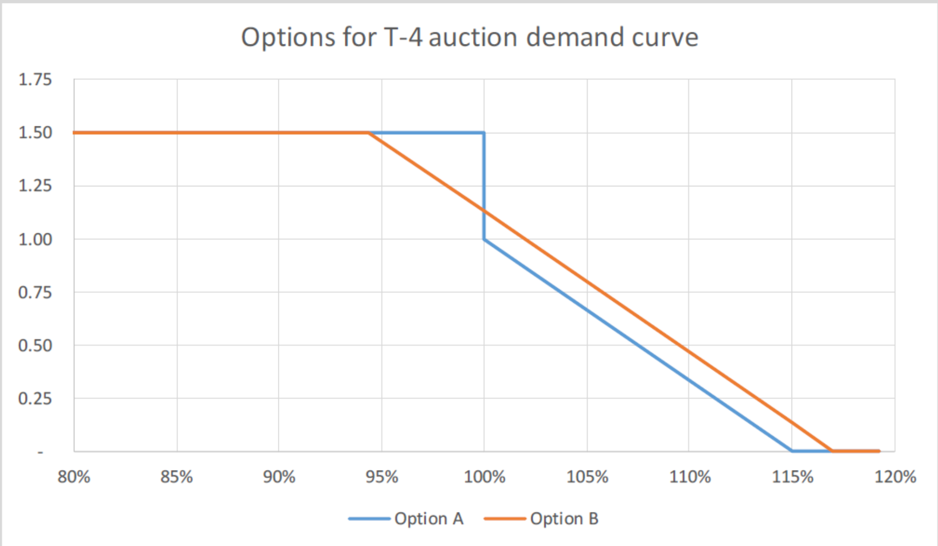
[42] This estimate assumes that all other factors remain fixed.

Capacity procured and security of supply

9.7 Net CONE is used to anchor the demand curve in the sense that, if the clearing price is Net CONE, the capacity requirement will be met[43] and therefore the security standard will be achieved.

9.8 The consequences of underestimating Net CONE depend on the shape of the demand curve used. The SEM Committee is consulting on the two options shown in Figure 1. The y axis is the ratio to Net CONE. The x axis is the percentage of the capacity required. Option A, as used in the T-1 auction, is vertical at prices above Net CONE. Option B continues to slope to the left above Net CONE.

Figure 1 T-4 Auction: Demand Curve Options



Source: Reproduced from CRM Parameters for T-4 Auction, SEM-18-028

9.9 If the value of Net CONE employed to set the parameters for the T-4 auction is underestimated, then:

a. In the case of Option A, at true net CONE there would be no change to the capacity procured; and

b. In the case of Option B, at true net CONE there would be less capacity procured and thus the system would be less secure.

9.10 Any over or under procurement of capacity could of course be adjusted in the subsequent auctions.

Conclusion

9.11 Underestimation of Net CONE can have real consequences for the willingness of investors to offer new capacity and for the volume of capacity procured, and so the extent to which the security standard is met.

43 In a T-4 auction, some of the CR may be deliberately held back for the later T-1 auction for the capacity year concerned. This refers to the volume of capacity to be procured in the T-4 auction.

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