Power NI Energy Limited
Power Procurement Business (PPB)

CRM T-4 Capacity Auction for 2022/23

Best New Entrant Net Cost of New Entrant (BNE Net CONE)

Consultation Paper

SEM-18-025

Response by Power NI Energy (PPB)

15 June 2018.

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Power Procurement Business

Introduction

Power NI Energy – Power Procurement Business ("PPB") welcomes the opportunity to respond to the consultation paper on the Best New Entrant Peaking Plant Net Cost of New Entrant for the proposed T-4 CRM auction for 2022/23.

In addition to this response, PPB also endorses the industry response submitted by the EAI and draws on the expert report commissioned by the EAI from Frontier Economics titled "Review of BNE / Net CONE for T-4 Auction" (the "**Frontier Report**").

General Comments

The methodology has been changed to consider BNE new entrants other than a peaking unit and the BNE proposed is a CCGT unit. The CRM is supposed to provide some revenue stability for generators (and costs for suppliers/customers) in the SEM. However it is not at all apparent that opting for a CCGT unit as the BNE one year and then switching to a Peaking unit the next provides that stability. In the first instance as the CRM is solely addressing capacity to ensure security of supply, and based on the assumption of a market at equilibrium and seeking a marginal capacity unit, it is unlikely that a CCGT would fulfil this criterion. To the extent it does marginally in the Poyry modelling, we have concerns that this is not robust. Poyry acknowledge that the modelling takes a simplified approach and the fact that small changes in assumptions e.g. in relation to IMR, DS3 revenues, costs, WACC, would give very different outcomes, raises strong concerns over the overall integrity of such an approach. It would also be the case that a rational investor would consider a very broad range of such scenarios to test the resilience to both normal volatility and extreme shocks.

We believe that the only sensible approach, to the extent a BNE price remains relevant in the SEM, is to determine the cost on the basis of a peaking unit. To the extent that an investor considers that it can earn sufficient additional revenues to justify the additional capital cost of building some alternative unit, then that is a decision upon which they can analyse and weigh up the risk/reward balance. However that is a much more complex analysis and should not be the basis of determining the cost of marginal capacity to meet a marginal increment in demand.

There is also a statement in section 2.3 of the Poyry report that "actual market outcome should not be ignored". However there is no attempt to understand if that entry has been rational and indeed, contradicts the statement by then selecting the BNE as a CCGT located in Northern Ireland when the "actual market outcome" has been location in RoI.

The Frontier report considers the proposals for the WACC and we highlight their conclusion that the Poyry analysis relies too heavily on regulatory decisions for regulated utilities and assets and that the WACC should be 2.5% – 3.5% higher.

While it is difficult for us to challenge many of the individual elements of the determination of the BNE price without procuring a report to challenge the Poyry report, there are a number of elements that we believe serve to understate the BNE price.

Our overall conclusion is that the BNE cost derived is too low. We reach this conclusion on the basis that many of the cost estimates are under-stated, the WACC applied is too low and the deductions for IMR and DS3 revenues are over-stated.

We provide detail on these deficiencies in our Specific Comments below and we also draw upon the review commissioned by the EAI from Frontier Economics.

Specific Comments

Selection of Reference Technologies

The criteria for filtering gas turbines includes units being commercially proven which Poyry adopt as 8,000 hours of commercial operation at 3 different sites. However the report then states in section 3.1.5.1 that "*the SGT5-2000E gas turbine received a significant upgrade in the last year*". The consequence of this has included an increase in capacity of c10%. However given this significant change, there is no clarification as to whether this substantially revised unit has since experienced 8000 hours operation over 3 sites.

There is also a statement in section 3.1.5.2 that "performance figures were based on ambient conditions corresponding to the grid's winter peak and this is the most likely scenario for utilisation of the peaking units". This is not strictly true and peaking units often operate where there is a coincidence of planned and forced outages and planned outages are rarely scheduled over the peak demand period.

The EPC costings in Table 2 appear counter-intuitive. If you multiply up the capacity by the Specific €/kW cost, one would expect the capital cost for Dual Fuel to be higher than Distillate only configuration. This is true for the first unit but for the other three units, the total EPC investment cost of Dual firing is lower.

The technical assumptions set out in section 3.1.5.3 state that it is assumed that the unit has no Black Start capability (and that if it did it would be remunerated). However in Northern Ireland, black start has always been a requirement but no NI generator receives any remuneration for the service.

There is also an assumption that the gas network pressure does not drop below 30 bar and hence no compressors are considered necessary. However the guaranteed pressure in N. Ireland is well below 30 bar and hence this assumption is incorrect.

Technology Selection for Reference CCGT plant

The technical assumptions set out in section 3.2.2.2 state that it is assumed that the connection voltage is 110kV in Northern Ireland. However it is clear from Chapter 7 of the All Island 10 year Transmission Forecast 2016 report that while a 200MW unit could be accommodated on the 110kV system, a CCGT of c450MW would need to connect to the 275kV transmission system. This has implications for the cost (which are stated to be lower in N. Ireland because of the connection at 110kV rather than 220kV).

As for the OCGT, there is again an assumption that the gas network pressure does not drop below 30 bar and hence no compressors are considered necessary. However the guaranteed pressure in N. Ireland is well below 30 bar and hence this assumption is incorrect.

Finally we note there is no consideration of the minimum generation level or RoCoF compliance of the CCGT although these are now also critical issues given high levels of SNSP.

EPC costs

We are not able to comment on the general EPC cost estimates. However, we disagree with the statement that the costs in RoI are higher because of the difference in the assumed voltage connection. As noted earlier, there is no capacity to connect a unit of over 400MW to the 110kV network in NI and hence the NI connection for a CCGT in NI would have to be at 275kV. Hence the NI CCGT should actually have a higher cost.

EPC contract duration

We believe the assumed construction periods to be too short. We consider a more appropriate assumption to be 24 and 36 months respectively.

Site Procurement costs

We do not agree with the proposition that site procurement costs have fallen in real terms since 2015. There has been a recovery in both RoI and NI and certainly land prices in NI have increased. We estimate that the costs should be 10-20% higher

Electrical connection costs

The electrical connection costs assumed are very low and are substantially lower than was used in the 2015 BNE decision which was €16.6m for the OCGT connection cost in NI which were determined after discussion with the TSOs. There is nothing to justify why this cost has now been reduced by €10.9m (c70% even before any inflation adjustment) to €5.7m.

The Poyry assumption is that the location is within 5 km of an existing substation whereas the previous estimate was for 2km of overhead lines. Hence the cost should also have increased as a consequence of the longer connection.

There is clearly an error in the Poyry estimates.

Gas and Water connection costs

The cost of the gas connection is derived from a 2010 data set. This will no longer be relevant and simple indexation to 2017 levels merely adds 8.8% to the cost. We doubt general inflation would be applicable given the increased rigour of environmental standards and the additional planning obligations. Hence even if it were appropriate to simply inflate the 2010 figures, a more appropriate inflator would be required.

Similarly, in relation to water costs, the cost has fallen in real terms with no justification but merely a reference to the cost being derived from the Thermoflow GTPRO software and associated PEACE module. There is no evidence to show whether this is relevant to the costs in Ireland and indeed why the cost would be the same in RoI and NI (e.g. given that RoI labour costs are higher).

Interest During construction costs

Based on our earlier comments on the duration of the construction project, we would expect the longer period would naturally increase the IDC cost.

In addition, the cost seems to simply reflect the interest accrued during construction, ignoring the opportunity cost of capital over the construction period. Frontier calculates that this could mean IDC costs are under-estimated by €2.5m for an OCGT and €24.3m for a CCGT, which are material costs.

Initial filling of the distillate fuel oil storage tanks

The cost of filling the storage tanks with the required fuel stocks shows a reduction of c33% over the cost used in the 2015 Decision paper. This seems to be driven by a lower fuel cost assumption which assumes €0.4/litre. The 2015 Decision paper was based on an oil cost of $58.13/barrel whereas the current cost has been in the range $75-80/barrel.and hence this would imply an increase relative to the 2015 decision. We estimate the current cost of fuel delivered price in excess of €0.5/litre and €0.65/litre when Excise Duty is included for NI stocks.

Commissioning Utilities Cost

Poyry assume that the revenue from electricity sales during commissioning will cover fuel costs following synchronisation. This might be true for a CCGT (although that may still not be the case overnight or during periods of high wind) but will not be the case for an OCGT. In addition, there is no mention of CO_2 costs in the assumptions but these are now becoming material given recent EUA costs are c€16/tonne and with much higher projection over the coming years. It also isn't clear if Testing Tariff charges have been taken into account. These could be significant when testing a 450MW single shaft CCGT unit.

Annual Insurance Costs

The insurance cost estimate is based on a cost of 0.6% of the EPC cost which is significantly lower than was used in the 2015 decision which used 1.6%. There is no justification for such a significant reduction and we are not aware of any significant change in the insurance market to warrant such reduction.

Annual Electricity Transmission charges

The estimate of Generator TUoS charges assumes the average charge in each jurisdiction. However, the tariff methodology is fluid and hence changes in load flows, which would be affected greatly with the introduction of a CCGT with a 75% load factor, would need to be considered. Charges are also affected by new investment and for example the investment in the North-South Interconnector could substantially change the GTUoS charges faced in particular by a CCGT located in N. Ireland. Such impacts would be considered by any investor and reflected in the assumptions and the WACC for the project.

Annual Gas Transportation charges

The Entry and Exit capacity costs for N. Ireland are based on the 2017/18 tariff. The proposed postalised charges for 2018/19 (and the subsequent 4 years) have recently been published by the NI Gas Market Operator and they show an increase of c29% (Entry and Exit charges increased to £285.87/MWh/day) compared to the prices used by Poyry.

This increase in an input cost that is unhedgeable highlights the risks that a gas fired unit is exposed to and this volatility and risk must be appropriately reflected in the WACC.

Costs Omitted from this BNE calculation

In previous BNE cost derivations, the cost of funding the initial working capital has been included in the derivation of the Annualised Capital Costs. In the 2015 decision this was c€2m for the OCGT (which would clearly be much higher for a CCGT). In addition the collateral requirements in the I-SEM markets are much higher for generators than is required in the SEM and hence this should be reflected in higher working capital costs.

The previous BNE calculations also included an annualised cost to reflect the opportunity cost of the cost of carrying fuel stocks. In the 2015 decision this amounted to €182k p.a.

There is no discussion on these omissions which we consider remain valid inputs into the calculation of a BNE cost.

Energy Market Revenues

PPB has consistently objected to the deduction of IMR from the BNE price and particularly the methodology employed since 2013 following the Medium Term Review. This remains our view.

In relation to the calculations performed by Poyry and set out in sections 5.1.1 and 5.1.2 of their report, the assumption to use 8 hours of full disconnection and 4 hours where there is partial ASP (implying reserve margin has been eroded) represents a lower security standard than 8 hours LOLE. The LOLE calculation adds up the probabilities across the year to reach an aggregate of 8 hours. That could be derived from 8 hours of disconnection with no risk at any other period, or it could be an amalgamation of a large number of small risks. However, the aggregate is always an 8 hour equivalent. The consequence of assuming performance that is lower than the 8 hour standard results in the IMR being over-stated. This is clearly incorrect and must be corrected.

The analysis set out in Tables 36-40 applies the FO rates to determine costs when the unit is unavailable but liable under the RO. However, this does not reflect the fact that any unavailability will not just be for 7.4% of the unit but the unit may be fully unavailable and causing the high prices. The concept of the Stop-Loss limits recognises this risk but this is not reflected in the Poyry analysis. Such risk should also be reflected in a higher WACC requirement.

The incremental cost of an open cycle gas turbine is assumed to be equal to €212.58/MWh which is in line with the assumption used for the 2018/19 BNE. However this does not reflect the increase in Oil and Carbon prices and hence must be updated to align with current commodity prices. As the BNE unit would be fixing the price for 10 years this calculation would also need to reflect the price movement assumptions over those 10 years with increasing oil and CO2 prices (as per the 2017 BEIS assumptions). The correct reflection of these will result in lower IMR receipts.

The calculations in sections 5.1.1 and 5.1.2 of the Poyry report assume that the De-rating factors are fixed. However, these may change and it isn’t clear how this risk is addressed. If the generator is to bear the exposure then this risk must be reflected in the calculations and/or WACC.

CCGT IMR

The IMR calculation for a CCGT assumes a 75% load factor, reducing gradually to a load factor of 65%. This may be plausible if there were no further new entry but it is likely that further new entry will emerge as older capacity retires or is closed for environmental reasons (e.g. Moneypoint coal). There are also plans for further Interconnection with Europe which is again likely to impact the load factors of indigenous capacity. As a result we consider the load factor assumptions to be optimistic. Further the evidence in SEM has been for CCGT load factors to reduce quite significantly after ten years of operation.

The recommendation in section 5.1.2.1 proposes a linear increase in IMR over the 10 year period. This increase, and the linearity of it, is very uncertain and cannot be hedged. Hence an investor is unlikely to place any significant value on this uncertain upside. Similarly, as evidenced in the market over the last number of years, load factors have fallen very quickly and hence a 5% IMR reduction each year from year 10 is also likely to be optimistic.

These load factor and commodity price trends therefore present a high risk and an investor/developer would analyse a range of scenarios and would take prudent assumptions on both the load factor and commodity price movements, and reflect the risk in their required WACC.

Ancillary Service revenues

The Poyry report ignores the risk of performance scalers and volumetric scalers both of which will impact to reduce DS3 revenues. It is also counter-intuitive to be claiming high load factors and also capturing average DS3 revenues. Units that are heavily loaded in the energy market will not be capturing DS3 revenues as they will be providing less reserve etc. Therefore a unit that is assumed to be targeting revenues in the energy market (and hence IMR) will be foregoing DS3 revenues. On that basis a CCGT should be capturing lower than the average DS3 revenues.

It is also questionable that a new CCGT will capture “enhanced” system services unless it invests to deliver these services. An “off the shelf” CCGT module will not be designed for flexible operation in a market such as Ireland and hence the provision of such additional flexibility will require increased capital and possibly operational costs whereas the Poyry reports seems to assume these are inherent. This has been the subject of heated discussion in the various DS3 forums.

WACC proposals

The Frontier Economics report commissioned by the EAI provides commentary on issues raised by the Poyry report which we support and which should be treated as part of our response.

We have also noted a number of areas above where there are risks that are distinct to participation in the SEM and thus should be appropriately reflected in the WACC required by investors.

We also question the recommendation set out in section 6.3.1.3 of the Poyry report to increase the gearing from 30% to 40%. This increase is not justified by any of the analysis presented and hence the gearing should remain at 30%.

The inflation assumption adopted in section 6.4.3 is 2%. This still leaves the investor exposed to variation in the outturn and again this risk must be reflected in the WACC used.

We also note the comment that GB adopted a 7.5% hurdle rate to apply in a market that is much larger and hence less susceptible to shocks and volatility. That would indicate that the WACC in SEM should exceed that GB rate.

Net Cost of New Entry

The derivation of the Gross CONE as set out in Table 52 of the Poyry report is not fully set out. However it appears that the Annualised Capital cost is derived by annuitizing over 20 years. In section 3.2.1 of the report, it was stated that “the debt tenor is assumed to be 10 years”. This implies that either the debt is fully repaid after 10 years or that the debt must be re-financed. There is no evidence to indicate whether either of these options is assumed and as a result the Annualised Cost will be under-stated.

We also note in the conclusions section (7.1.3) that Poyry argues that there is a case for the WACC for the OCGT to be lower than that for a CCGT. We have already highlighted that we believe there are a number of risks that have not been reflected in the WACC and as a result, rather than considering that the OCGT WACC could be lower, we consider both should be higher and with the CCGT WACC being the higher given the substantial risks relating to IMR, DS3 revenues etc.