Power NI Energy Limited
Power Procurement Business (PPB)

I-SEM Detailed Design

CRM Parameters Consultation

Response by Power NI Energy (PPB)

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Power Procurement Business

Introduction

PPB welcomes the opportunity to respond to the RAs consultation on the Capacity Remuneration Mechanism (CRM) detailed design consultation on the CRM Parameters.

General Comments

This consultation is one of the most important as the CRM represents the revenue stream that will recover the residual revenues that generators need to ensure revenue adequacy in the I-SEM. While superficially this may not seem to be as important a consideration for customers, it is vital as it sets the overall context of the I-SEM as a market into which investors will make their decisions on whether or not to invest. If there is a revenue adequacy shortfall or if regulatory risks are higher than in other markets then capital will not be committed into the I-SEM and customers will end up bearing higher costs to compensate and to ensure security of supply is not compromised.

Our primary concern with the SEMC proposals for the CRM parameters is that the SEMC is seeking to price regulate the CRM in a similarly prohibitive manner as it has proposed for the offers in the Balancing Market, adopting a blanket approach when the primary objective of managing market power should be to apply targeted and focused actions on the source of the problems and letting competition prevail in the wider market among those who do not possess market power and who are already commercially incentivised.

Further, having proposed measures in the BCOP that, if implemented, would mean generators could be operating at a loss in the Balancing Market, the SEMC are also proposing to cap bids for existing generators at a low level in the CRM that is based on a definition of Short Run Fixed Operating Costs that provides little or no scope to capture any Inframarginal revenues in the CRM that would contribute to remunerating the capital and debt invested in the generating assets or to provide any return on those assets.

Such an imposition would destroy any incentive to invest in the I-SEM, be that in new capacity which would have to take regard of the non-recovery of costs once its maximum 10 year contract expires, or be that in decisions in how to maintain and refurbish existing capacity. This latter point creates a very difficult situation as the definitions mean that any investment in maintenance or refurbishment that would normally be amortised over a number of years would be a “sunk” cost after the first year and would not be part of Net Going Forward Costs (NGFC) in subsequent years. Hence the option would be to seek to recover all the investment in the year it is made, which would inflate the cost if it were to be successful but equally may make the NGFC so prohibitive in the year that the unit is unsuccessful and as a result closes, potentially requiring a new entrant with a long term contract to replace the capacity. This results in a high risk of a distorted outcome that is uncompetitive and inefficient and which cannot represent the least cost outcome for customers and is not therefore a sustainable market framework.

We attach a report from NERA[1] that was commissioned by Viridian Group which provides NERA's assessment of the SEMC's proposals for bidding controls in the I-SEM CRM and specifically comments on how the proposals would affect competition in the I-SEM and ultimately the effect on customers. NERA conclude that the SEMC proposals are based on a flawed interpretation of the theoretical ideal of perfect competition, that do not reflect the real world conditions and longevity of investment decisions in electricity markets. The report also highlights that there are no international precedents to support the SEMC proposals and in all other markets there is more emphasis on creating a competitive framework that provides greater flexibility to participants, rely on ex-post scrutiny where necessary rather than prescriptive ex-ante controls and do not seek to deny total cost recovery (i.e. enabling revenue adequacy). NERA conclude that the SEMC proposals will distort the market, skewing it towards expensive new capacity which will be inefficient and expensive for customers.

[1] NERA Report titled : "Competition and cost Recovery under the I-SEM Bidding Rules – A report for Viridian – 19 December 2016"

Responses to the Specific Questions

Chapter 2. Administered Scarcity Pricing parameters

Q1: The SEM Committee welcomes views on all aspects of this section, including whether you prefer Option 1 (as set out in Section 2.2 above), Option 2 or some intermediate option for the shape and slope of the ASP function, and why?

Paragraph 2.1.6 states that the TSOs will invoke involuntary load shedding before qSTR reaches zero and that whenever the TSOs do this the ASP will default to FASP. This means that the actions of the TSO will distort pricing in the balancing market. We consider the ASP should always be derived based on the qSTR margin that would be derived by adding back the volume of any load shedding. To do anything otherwise would mean the ASP curve would not be a smooth curve and would increase vertically at a number of MW greater than zero to FASP. However the point at which this happens will be dynamic and could be driven by TSO forecasting errors or by differing degrees of prudence adopted by different control engineers in the TSO control rooms. Such vagrancies should not be influencing market pricing and participant exposures and prices must be driven by objective and transparent causes. Adding back the volume of any load reduction and continuing to apply the ASP curve will provide a truer reflection on the pricing and reduce the risk of TSO actions influencing or distorting prices.

We have similar concerns with the proposals in paragraph 2.1.7 which calculates prices every 5 minutes. This also highlights that within settlement period spikes could affect pricing and again could be driven by TSO decisions, for example, to carry less POR, SOR, TOR, and RRS which could have been dispatched to provide adequate levels of reserve but which for some reason the TSO decides not to do. Participants should not be exposed to such TSO actions affecting market pricing and only bona fide shortages should trigger ASP and TSO decisions and actions must be excluded from pricing.

The TSOs modelled LOLP curve shown in Figure 3 is counter-intuitive and one would expect that for each 100MW reduction in reserve the Change in LOLP would increase (an exponential decay curve as the simple piece-wise linear ASP curve in Figure 2 illustrates) whereas the graph shows lower changes per MW reduction in reserve as reserve approaches zero.

We believe the curve should be more like the curve in Figure 2 which would reflect our expectation of how LOLP changes as reserve margin increases. We would therefore support such a curve that only increases substantially as the reserve margin approaches zero.

We do not support a curve as shown as Option 2 which we consider is penal and counter-intuitive to normal expectation. We therefore suggest that further investigation is needed to confirm the accuracy of the analysis. Whatever the outcome we consider a conservative approach should be adopted at least initially given the transition to a new market and hence we would favour a dampened approach, i.e. Option 1 over Option 2, notwithstanding we consider that the correct curve would be lower than option 1 but rising more quickly as the reserve margin approaches zero.

Chapter 3. <u>Cost Recovery and Charging</u>

Q1: Which of Options 1 to 3, as set out in Section 3.2, do you think is most appropriate, and why? Alternatively, what other definition of the Supplier Charging Base would you chose and why?

PPB is not a supplier and hence will leave it to suppliers to respond to this question. We would however note that historic LOLP is somewhat of a misnomer since the demand was known and was either met or it wasn't and hence there is no forecast range and no "probability". As a result, the value of the analysis in Figure 5 is questionable.

We are also surprised that there is no assessment of the impact of the different allocation methods on different customers groups.

Q2: Which LIBOR (or other such reference rate) should be used as the BIR, and what the values of the SPR and DPR should be?

No response.

Chapter 4. ***Reliability Option Parameters***

Q1: Do you agree with the SEM Committee's proposed approach to set the DSU floor price at €500/MWh?

The reasons to limit the DSU floor price to €500/MWh are not well justified and it is not clear if placing such an artificial limit will distort or discourage new DSUs from participating in the market.

Q2: On the assumption that the gas index will be a reference price related to gas obtained from the GB system, do you agree with the carbon intensity factor? Do you have another comments on the approach to setting the gas or oil carbon intensity factors?

The critical decision relates to the reference fuel which must be a daily index since otherwise the RO will not reflect the real underlying price movements and volatility in the electricity market. Once these reference fuel indices are determined then the carbon intensity will just need to be captured based on the carbon content of the fuel specification covered by the index, taking account of the correct HHV or LHV basis upon which the fuel is traded.

The CRM delivery body is not involved in the procurement of fuels and as a result they are ill-equipped to propose an appropriate reference fuel index. It would be more appropriate to consult with market participants on the appropriate reference fuel index such that the expertise of active fuel purchasers can be garnered.

Q3: Do you agree with the approach to setting transport adders set out in section 4.4?

It is not clear why the CRM Delivery Body is being charged with determining the transport adders. The charges for gas transportation may be largely based on tariffs but the examples shown in Table 2 only reference the Commodity elements when there are also marginal daily capacity charges that apply at both Entry and Exit. Further some of these charges have a tariff rate as the reserve price in an auction but where the actual cost could be higher. In addition there are risks that the gas transportation capacity cannot be secured and as a result penalty charges apply. Such costs and risks should be reflected in the transport adders and it is not apparent that the CRM Delivery Body has the knowledge or expertise to propose appropriate figures.

The costs for transportation adders for solid and liquid fuels are commercial costs. As the CRM Delivery Body is not actively purchasing fuels, it is difficult to identify why they are deemed to have the knowledge or capability to make any recommendations as to what the appropriate costs are for delivery of fuels to different locations in Ireland. Previously such costs were provided by some market participants on a confidential basis to the RAs as part of the PLEXOS validation exercise. It would seem more appropriate that such information is obtained on an ongoing confidential basis from active participants who have direct knowledge of the costs and for the SEMC to then consult on those.

Q4: Do you agree that the Billing Period Stop-Loss Limit should be set to 0.5 times the Annual Stop-Loss Limit (i.e. 0.75 times the Annual Option fee)?

We believe the figure of 0.5 times the Annual Stop-Loss Limit to be too high. It might have been appropriate when the Billing Period for capacity was expected to be monthly but now that the Billing Period is to be weekly, this implies that the full Annual loss limit could be exhausted over the course of 2 weeks. Planned outages often overrun and there have been recent examples of this extending beyond 2 weeks. Unplanned outages also often last for more than 2 weeks, particularly when external contractors need to be mobilised and where the fault is not one for which spares are held on-site. Hence having a Billing Period Stop-Loss limit set at 0.5 the annual limit (or 0.75 times the annual option fee) creates a high degree of risk for a generator.

This risk was recognised in the CRM Decision paper 2 which acknowledged the trade-off between providing incentives and limiting the risk to the capacity provider. However, the primary purpose of the CRM is to provide less volatile revenue streams as there will always be a commercial incentive to make capacity available, if at all possible, when margins are tight and irrespective of whether or not a generator has an RO or whether the stop loss limit has been reached.

Setting the Billing Period Stop-Loss limit at the level proposed exposes the generator to virtually the full market risk and negates most of the “stability” benefits of the CRM. The actual cash payments that would be involved should a generator be unavailable over the course of a billing period during which there is scarcity would also have a very significant impact on the collateral and working capital requirements for a generator and potentiality its commercial viability. This risk and the subsequent effect is also likely to be more pronounced for a single unit generator who doesn't have a portfolio from which it could benefit from offsetting gains arising from the margin between the de-rated and gross capacity of other units in a portfolio. The potential to access other management tools such as secondary trading is also unproven and in any event is likely to have priced the scarcity into any such trades as soon as outages are known. As a result, the risks of adopting such high stop-loss factors will likely make investment more difficult which will sustain the concentration and market power problems in the I-SEM.

Our preference would be for a lower Billing Period Stop-Loss limit. The original proposal of 0.5 as a monthly limit would be equivalent to a factor of 0.125 times the Annual Stop-Loss limit, when converted to a weekly limit. We believe this is more proportionate and better fits with the objectives of the CRM and providing less volatile revenues rather than increasing risks for participants, as we believe would be the case if the 0.5 times the Annual Stop lost limit were adopted.

Chapter 5. <u>New Build, Termination Fees & Performance Bonds</u>

Q1: You agree with the approach of setting the New Capacity Investment Rate Threshold at around 50% of the gross investment cost of the BNE plant, currently estimated at €310/kW? If not, what is an appropriate maximum size of termination fee for new capacity which achieves an appropriate balance between protecting consumers by the failure of new capacity to deliver, and not providing a barrier to entry for new capacity?

The factor of 50% is not well justified and the resulting cost of €310/kW is nearly double the rates used in GB. The risk of setting such a threshold too high is that it will distort future investment decisions that could result in higher costs for consumers e.g. because refurbishment investments cannot recover their costs as they only receive a 1 year contract and once the investment is completed, it is treated as a sunk cost that is excluded from the Net Going Forward Costs calculation. This effectively concentrates the investment decision into a single year decision that will make any significant investment very difficult and even ongoing maintenance investments difficult to justify on a commercial basis.

Q2: You think that the SEM Committee's indicative schedule of termination fees set out in paragraph 5.3 is appropriate? Please provide evidence for your answer.

No response.

Q3: It is appropriate to place termination fees on capacity that does meet the definition of New Build, and if so, at what level, including:

1. ***Minor refurbishment or other upgrades to capacity which does not meet the financial threshold to qualify as New Build;***
2. ***Unproven DSUs;***
3. ***Any other capacity provider which has not already demonstrated its ability to physically deliver;***
4. ***All existing capacity***

There is no need to place termination fees on capacity that is only given a one year contract. As the paper notes, the provider will be obligated to provide collateral and make difference payments. Adding a further termination fee will increase the regulatory risk still further which, in a competitive environment, would ultimately increase costs for consumers since the obligation would be expected to result in higher CRM prices. Where this does not happen, for example because of market power or non-commercial bidding by large portfolio players in the market, the delay in recovery of any such additional obligation will instead manifest as a security of supply risk for consumers by increasing the barriers for new entry into the market. In both cases the outcome will be higher costs for consumers and the only difference will relate to how soon that occurs.

Q4: Performance Bonds should be required for 100% of termination fees, and should this vary by type of capacity?

The level of the performance bond seems like a logical position although it isn’t obvious why there should be any variance across capacity types.

Chapter 6. <u>Auction Parameters</u>

Q1: Do you agree with the proposed adjustments to the BNE calculation approach set out in section 6.2.8 to 6.2.10 If not, explain why.

FO rates

There is no necessity to align the forced outage rate with assumptions used in the de-rating methodology and it is more important that the true underlying FOP is used for the BNE.

IMR deduction

The IMR that a unit can earn is capped at the RO Strike price and adjustments must be made to reflect that. However the methodology that is applied is wrong. The proposition that there will be Partial ASP represents a very concerning misunderstanding of the security standard and the derivation of 8 hours of LOLE. The determination of 8 hours LOLE may in fact have no or only a few actual losses of load and the remainder is made up from the aggregate of LOLE where there is a risk of loss of load but not an actual loss. As a result the 8 hour security standard is an 8 hours equivalent that is made up of an aggregate of many periods of Partial ASP and the proposals in the paper would by definition have greater than 8 hours LOLE if you assume 8 hours where there would be insufficient generation and further hours with a high risk of loss of load. As a result, the IMR revenues will be much lower than has been forecast and one proxy would be the full 8 hour scenario but ignoring the Partial ISP.

Note also that there is an error in Appendix C under the forced outage row where an RO exists. The Strike Price should not be deducted in the formula as during a forced outage, the generator has no revenue and is liable for the full repayment and hence under the row labelled “Covered by RO (95% of Capacity)”, the calculation should be [-(3000) x 8 x 5% x 95% = -1140]. Adjusting for this in Appendix C and ignoring the Partial ASP (which is double counting) the IMR is the equivalent of €2.36/kW p.a.

Finally, as the RAs acknowledge, the expectation is that there will be more capacity contracted, particularly in the transitional period, because of the locational constraints and because units will not initially close (e.g. due to the stated requirement to give 3 years notice of closure). As a result the LOLE is expected to be much lower than 8 hours and as a consequence, there will be fewer scarcity periods and IMR will be much lower. Similarly, the proposal is for the strike price to be indexed to monthly fuel prices which are less volatile than actual spot fuel prices. This mismatch means there is risk for RO providers that will further erode IMR and this also needs to be reflected in the IMR calculation.

Adjusting for De-Rating

We agree that the Net CONE price needs to be adjusted for de-rating by dividing by the de-rating factor.

Other Adjustments that are required to the BNE and Net CONE price

The calculation of the BNE requires much more substantial updating to take account of a number of other changes resulting from the I-SEM market design. These include :

1. The term of financing must be reduced to a maximum of 10 years to reflect the maximum contract term that is proposed for new entrants. This is important as the proposal to cap existing prices at the Net Going Forward Costs (NGFC) which specifically excludes any sunk investment costs means that if a new investor is to recover their investment it will need to be recovered over the term of its long term contract;
2. The WACC will need to increase to reflect the additional risks that a generator will be exposed to in the I-SEM which are much greater than in the SEM. These include the risks relating to performance bonds relating to construction, the RO risk whereby the generator could have to pay back up to 1.5 times the capacity payment and other generally increased market and regulatory risks (inc. risks that energy market revenues are capped below cost as proposed in the recent consultation paper on Offers into the Balancing Market – SEM-16-059); and
3. A BNE unit in the I-SEM will have higher ongoing costs, including in relation to collateral and working capital costs and these need to be included in updated costings that ultimately result in the Net CONE price.

Q2: Do you agree with the choice of multiple of 1.5 x Net CONE in setting the Auction Price Cap?

We believe the multiple should be set at the upper end of the range, i.e. 2 x Net CONE. We understand 1.5 to be at the lower end of the range seen internationally. The I-SEM is a small market and new investment tends to be lumpy relative to the annual incremental growth in peak demand. Therefore there is a high risk for customers if the cap is set too low since no new entrant could then justify an investment. On the flip-side, there is less risk for customers from setting the cap more generously as there is greater scope for competition to compete the bids down.

This asymmetry is at the core of the concerns with the overall SEMC approach which seeks to apply a unilateral regulated approach to all areas of the I-SEM rather than relying on competition to deliver the most appropriate outcomes and only intervening in a targeted manner when measures to mitigate specific market power are needed.

The justification outlined in paragraph 6.2.19 is that capacity providers have found that "*a capacity payment of less than 1 x Net CONE adequate to cover missing money*", ignores a number of exceptional circumstances that have persisted since the commencement of the SEM including the economic downturn and the continued economic support for renewables. This also ignores the fact that there has been no new build in Northern Ireland despite there being a clear requirement (and the BNE plant being NI based) and out of market contracts have been employed to retain 250MW in NI. Such history will have no bearing on future investment and it is also noteworthy that there is a significant volume of capacity approaching the end of its life and that some new capacity will be needed which will require investment. We therefore believe that it would be better to have a higher cap that does not create a barrier to investment and allows normal competitive forces to minimise the cost rather than seeking to impose a tight cap that risks impeding any investment.

Q3: Do you agree with the proposed methodology of estimating a generator's Net Going Forward Costs (NGFC) at:

Max[(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets),0] + Expected Reliability Option difference payments

No. The paper mixes up missing money and NGFC throughout and basic cost recovery does not imply that a generator has recovered its missing money. As noted earlier, generators will need to recover their investment with a reasonable return over the lifetime of the investment. The proposal to limit recovery to NGFC does not correlate with missing money or with enabling a generator to recover sufficient funds to remunerate its investment.

The decision made is that generators can access a contract for up to 10 years, after which the generator will be an Existing generator but for which any "sunk costs" are not part of NGFC (as per para 6.3.9). However, such a generator may still have some unremunerated investment that it needs to recover when it is an "Existing" generator and it will have new investments to make for major maintenance or life extension works that the methodology to determine NGFC will not remunerate. This will have a major distortive effect on the decisions of both potential investors who will see this unremunerated tail to their prospective investment, and to existing generators who need to make decisions on how they operate and maintain their generating units. In both cases, investors will find it difficult to justify committing capital against which they may not receive any recovery never mind a return. This will inevitably increase risks to security of supply and increase costs for customers in the longer term.

The proposed definition of NGFC seeks to over-simplify the calculation of the costs that a generator will need to recover if it is to continue to participate in the market. These must relate to its total costs and not a simplified variant that seeks to cap costs at "Fixed operating costs" which will not enable marginal generators to recover any IMR in either the energy or capacity markets to remunerate their investment over the lifetime of their generation asset.

Q4: Do you agree with the proposed process and data inputs to calculate NGFCs as set out in 6.3

We do not agree with the proposed process that seeks to impose tight price regulation across the market. This is a disproportionate approach that will distort competition and is not targeted at specific market power in the market. It is instead more likely to discourage entry by independent investors and penalise smaller existing participants which may result in increased market concentration.

Our other major concern is that the aggregate of bidding controls proposed by the SEMC covering both prices in the Balancing Market and in the CRM will mean that it will be impossible to make a reasonable return on an investment in the I-SEM and as a result the market will be unsustainable. The approach to treat existing investments as sunk costs that therefore do not merit any remuneration represents an opportunistic short term view that we believe to be myopic since any such imposition will contaminate views on the merits of investing in the I-SEM, which is not in the long term interest of customers.

Considering the proposed general approach and the data inputs, the use of the Generator Financial Reporting of Non-Fuel Operating Costs (NFOC) as a proxy for Fixed Operating Costs is likely to be flawed. We expect very different interpretations will have been taken by respondents and therefore the data will be inconsistent and would require significant data adjustment to ensure all the information is stated on the same basis. In addition, the data the SEMC propose to use relates to 2014 when the capacity year for the first T-4 auction is likely to be 2021 and costs are likely to have changed significantly over that time period.

The next step proposed is to adjust these values in an undefined manner for variable costs and to set some efficiency gain incentive. This seems to imply that all generators in the market are inefficient and have no commercial incentive to reduce costs. This however belies the fact that all independent generators are already fully incentivised to maximise profits and hence to minimise costs. Any adjustment the SEMC would propose is likely to be arbitrary and subjective and will again highlight regulatory risk in the I-SEM.

The next step is to calculate unit specific IMR. This will be prone to a high risk of error given that the market is new and pricing in the different market timeframes is uncertain. The Euphemia trialling was not focused on correlating pricing between the SEM and I-SEM and the results showed wide degrees of variance under different scenarios. There has been no trialling of the IDM and the BM pricing rules are as yet untried and pricing will be heavily dependent on how the Flagging and Tagging process operates in practice. There also remains uncertainty over how Wind and Demand will participate in the markets, which in the case of wind may depend on how the support mechanisms are amended. Similarly for DS3, one would expect many of the DS3 revenue elements, particularly those that are only earned when a unit is synchronised, to be reflected as opportunity costs in energy market bids and therefore reducing prices in the energy markets.

In addition to these “new” elements for the I-SEM, there are all the normal forecasting assumptions that could have a significant impact on the results, particularly when looking 4-5 years ahead, including demand, plant build and closure (inc. renewable incentives and build), commodity pricing, and electricity prices in GB and Europe and the resulting impact on I/C flows. These all highlight the difficultly in forecasting Energy and DS3 market outcomes and revenues and there is a high risk of error.

The evolution of the DS3 budget is also uncertain and the proposal appears to envisage some form of linear scaling of revenues based on the change in the overall budget. However there is no evidence to suggest that this will be the case and indeed the payments for different services could change substantially from what exists in the current tariffs. Hence this scaling approach also appears to be overly simplistic.

As a result of the potential for significant error, a large margin would be required to ensure that market participants are not constrained from bidding at a level that would allow them to cover their actual estimate of NGFC (which as we have already outlined also needs to be redefined to allow for costs beyond those proposed by the SEMC).

Q5: Do you agree with the proposed approach of setting the Existing Capacity Price Cap at 0.5 x Net CONE? If not explain why, your preferred alternative approach and your rationale for the alternative.

We have already explained above that the Net CONE cost needs to be recalculated to reflect among other things, the 10 year contract term and a higher WACC to reflect the higher risks in the I-SEM. Further to that recalculation, we do not believe that an arbitrary figure of 0.5 should be used and the rationale proposed by the SEMC is poorly founded. As we have noted above, there is a high potential for forecasting error and further, the process to seek to obtain approval for a higher NGFC that is in excess of the Existing Capacity Price Cap is resource intensive. In addition, it is unclear why existing capacity is again treated differently to new capacity with respect to price caps and this is again discriminatory. A MW of capacity is just that when providing the capacity to customers and customers do not have a different value of VOLL for new capacity relative to existing capacity and therefore creating an artificial difference only serves to highlight the flawed design that distorts pricing by creating two distinct products when customers are only interested in a single product that delivers security of supply to the requisite standard.

We have also highlighted in response to earlier questions that the risk to customers from setting the cap too low is much greater (risk to security of supply and higher cost of capital to participate in I-SEM) than the cost of setting it too high where bids could be expected to be competed down and with scope for ex-post review of bids.

The rationale set out in paragraph 6.3.33 states that most plant would be able to bid without seeking a higher unit specific limit. However it would seem more sensible, if there is a limit, to set it at a margin above the highest cost unit to allow for forecasting errors. The second rationale is that it is consistent with “international benchmarks” but there is nothing in the consultation paper to support the statement or evidence that the comparison is appropriate and/or proportionate for the I-SEM. Our understanding is that there is no relevant precedent or international standard and there is no alignment with what has been adopted in GB where ex-post scrutiny may be employed and even then only where there are concerns over a bid. Furthermore, there are no explicit restrictions on energy market bids in GB and hence GB generators have a number of options to enable both the recovery of missing money and to remunerate their investment over the term of its life.

The I-SEM proposals are much more onerous, restricting bids to SRMC (or lower, based on some of the costs the SEMC are seeking to exclude under both the BCOP and under the Existing Capacity Price Cap and the NGFC proposals), which will not provide any contribution to the remuneration of the original investment or to providing an adequate return thereon, and which will affect an increasing number of units whose scheduling is volatile and driven by the availability of wind.

Q6: Do you think that the NOFC costs reported by generators to the RAs as part of the SEM Generator Financial Reporting are a good proxy for the Fixed Operating and Maintenance costs that a capacity provider may need to recover via the I-SEM CRM, or do you think that the NFOC contain material variable cost which can be recovered via the energy / ancillary services market? If the latter, how big an adjustment should the SEM committee make to exclude any variable elements of the NFOC from NGFCs included in the Existing Capacity Price Cap?

As we note above in response to Q4, the information provided to the SEMC as part of the Financial reporting returns will be based on historic costs and will be conditioned by the accounting standards and the interpretation thereof that any individual generator employs. Within this there are likely to be substantial differences and therefore substantial effort would be required to ensure they are stated on exactly the same basis.

Even then, they are a report on history and do not provide reliable information on future costs which will change as a unit ages, as demand profiles change (e.g. as a result of DSM, energy efficiency, Smart meter roll-out, etc), and as the plant mix changes both as a consequence of the exit signals the CRM will provide and as a consequence of the ongoing impact of decarbonisation and the mix of low or zero carbon technologies that develop in the market, all of which will have a different impact on the operating regimes, maintenance requirements and investment requirements of existing generating units.

As an example, PPB trades the Ballylumford CCGT units that have been the swing units in the SEM over the past 4-5 years which has seen market load factor reduce substantially, significant constrained running and with significantly more starts that any other unit in the market. In the last 4-5 months the load factor has swung again following the increase in coal prices, outages on other capacity and shortages in GB. Such changes cannot be captured from a simple consideration of historic costs. Hence while the data may not be an issue for baseload units, the more marginal units and those affected by a coal – gas price flip will require a detailed consideration of future costs.

Q7: Why are reported SEM generator NFOC/FOM costs substantially higher than international benchmarks? Do you think that existing SEM generators have material scope to cut fixed operating and maintenance costs, and if yes, do you think that this should be reflected in the Existing Capacity Price Cap? Explain why.

It is not possible to comment on the relative costs without conducting a detailed analysis of the individual components to the level of individual line items as it is likely that there is a wide variation in interpretation and cost categorisation.

It is surprising that the SEMC seems to consider SEM generators are wilfully incurring higher costs than is necessary. There is no reason to believe Independent generators who have an absolute incentive to maximise profit and hence minimise costs are ignoring such opportunities and are bearing costs inefficiently. In N. Ireland, the generators were sold to international investors in 1992 and those purchasers were commercial organisations with portfolios of generation across the world against which they could benchmark costs and profits. It would be extremely surprising for such commercial organisations to wilfully incur costs at any level above what is necessary and there is no evidence that this is the case.

Aside from the cost classification point, there are likely to be a number of reasons why costs in Ireland will be higher. These include, but are not limited to, (i) economy of scale, (ii) more onerous Grid Code Obligations because of the small system and need to provide range of ancillary services, (iii) Transmission Use of System Costs, (iv) Gas transportation costs (inc. postalised charges in NI such that electricity generators are subsidising the cost of gas transportation to other downstream users), (v) requirement for dual fuelling with associated maintenance costs and working capital costs for fuel stocking, and (vi) the operating modes of units in Ireland that have much more intermittent operation to intertwine with the intermittent wind output.

Without a thorough examination of the accounting treatment of the costs and the underlying cost drivers, it is not possible to draw any meaningful conclusions from the comparisons set out in the consultation paper. However, as we note above, all the independent generators in Ireland have been fully commercially exposed (in the case on NI generators since privatisation in 1992) and hence we would not expect there to be any extraneous costs in their cost base.

When considering a new entrant peaking plant, it will need to recover its total investment cost, operating costs and a reasonable rate of return to justify an investment. The BNE calculation already assumes efficient fixed operating costs in its derivation and hence if investment is to be made, the new entrant will expect full recovery of these commitments, including its fixed operating costs. Any sense that an arbitrary reduction would be applied on top of the already arbitrary cap proposed at 50% Net CONE will either result in an increase to the Net CONE to reflect the additional risk and potential reduction in its merchant tail revenues, or a decision not to invest that risks security of supply for customers. In both cases, customers will bear an additional cost which we believe in unwarranted and avoidable.

Q8: Which of options A, B or C with respect to the demand curve set out in Section 6.4 do you think is appropriate for the first transitional auction, and why?

We believe it would be prudent to smooth the transition into the I-SEM and therefore consider Option A would provide the most appropriate option. As we have previously identified, the actual capacity margin required by the TSOs has been much greater than what has been determined as the capacity requirement (as we highlighted in our response[2] to the Capacity requirement consultation in 2015, when considering NI in isolation it showed an actual margin that was in excess of the margin determined for the whole of the SEM).

The shallower slope under Option A will better facilitate securing additional capacity to meet the actual customer requirement, although as we have commented in response to the Capacity Requirement and De-Rating consultation, the determination of the Capacity Requirement must be corrected to align with the GAR analysis of the requirement.

Option A also best mitigates the lumpiness problem and may also reduce the locational requirement.

[2] *PPB response dated 22 June 2015 to SEM-15-032*

This should not be a one-off process and the demand curve for future years must be subjected to the rigour of detailed analysis and a full consultation with industry.

Q9: Do you have any other comments on the shape and/or positioning of the demand curve for the first transitional auction?

The CRM must be coherent and set the framework for a stable and enduring mechanism that does not introduce additional regulatory risk that will deter investment. While the transitional demand curve is important, it is less important than (i) ensuring that the Net CONE price is appropriately determined to reflect the new contractual framework and risks in the I-SEM that are very different to those that applied to a BNE in the SEM, and (ii) on the critical determination of the ECPC which must be set less in the manner of a price control (although even a network price control would allow recovery of depreciation and a return on “sunk” network investments) such that it does not create volatile and unpredictable exit signals but rather allows generators the prospect of recovering their costs and allows competition to operate, subject to safeguards to avoid predation.

Q10: If the SEM Committee proceeds to incorporate locational requirements within the I-SEM CRM, do you agree that the costs/risk of implementing local demand curves (as opposed to a minimum requirement) outweighs the benefits?

It is difficult to comment on the costs/risk of implementing local demand curves given the sparsity of information provided on the costs and the risk. However adopting Option A for the overall demand curve may reduce the volume of locational contracts that are needed.

Chapter 7. <u>Load Following for Secondary Trading</u>

Q1: Do you have any comments on the approach to setting the load following parameter set out in the section? Specifically do you agree with the granularity of the parameters, the proposed historically based methodology, and proposed governance approach? If not, why not and what other arrangements would you propose?

Higher levels of granularity should enable the volumes of capacity available for secondary trading to be maximised. While we can understand the trade-off, the use of monthly factors may be restrictive in winter months. A better approach may be to apply a weekly granularity which would provide some additional flexibility. An alternative may be to adopt a hybrid with Monthly factors from April to September and Weekly factors from October the March.

An absolute focus on historic patterns may not be efficient and we would prefer that some forward looking analysis is also included. The TSOs will, we expect, be looking forward when they are undertaking their outage planning and at the very least that should be an input into the process.

Whatever process is adopted, it must be transparent and if the TSOs are charged with making proposals for the SEMC to approve then the methodology must be clearly documented such that there are no shocks and that the TSOs are not adopting an overly prudent approach that reduces potential liquidity in the secondary market.

Q2: Do you think that capacity providers should be able to trade against load following margin in calendar year +2 and any subsequent years, and should the parameters for subsequent years be scaled to 75% of the calendar year Y+1 values or some other percentage?

It would be useful if participants could trade further ahead and at least as far as Y+2. We acknowledge there may be some uncertainty over the factors and hence consider adopting a factored approach for Y+2 would be a sensible compromise.