

**Power NI Energy Limited
Power Procurement Business (PPB)**

**I-SEM
High Level Design for Ireland and
Northern Ireland from 2016**

Consultation Paper

SEM-14-008

Response by Power NI Energy (PPB)

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Executive Summary

Power NI Energy – Power Procurement Business (PPB) fully supports the objective of the I-SEM to maximise efficiencies by optimising electricity flows on interconnectors and welcomes the opportunity to comment on the options proposed for the High Level Design of the I-SEM.

CRMs

PPB believes a CRM is essential in the Irish market for all of the reasons the existing CPM was established and that the growing penetration of renewable generation which is reducing load factors on conventional generation further reinforces the ongoing need for a CRM (noting that this latter issue is driving proposals for CRMs elsewhere in the EU).

PPB considers that the current form of the CPM (i.e. a long term price based CRM which already includes the demand curve to scale revenues depending on the capacity surplus/deficit) remains the most appropriate mechanism. PPB has drawn upon an independent assessment completed by NERA for Viridian Group to help our understanding and assessment of the need for a CRM and wider issues on the high level CRM design options.

We believe the SEM Committee (SEMC) should determine that the current CRM should continue largely in its current form and this would maintain regulatory stability in this area while efforts are focused on the implementation of a revised energy market that complies with the Target Model requirements. If the SEMC are not minded to agree that the current model is fit for purpose, then we believe significant further investigation and consultation on alternatives will be required before a decision could be taken as the options outlined in this consultation are merely high level conceptual descriptions and require significantly greater definition before proper consideration could be completed.

Scope of considerations for the HLD

PPB is concerned that the evaluation and scope of the HLD options may be too narrow and that it is at this stage that the totality of the electricity market design must be considered, ranging from consideration of how a liquid forward market will be delivered, given this is the market that generally determines customer prices, through to the real-time balancing market. PPB suggests four areas where the scope must be broadened such that these elements are addressed at the HLD stage. These areas are :

- (i) Determining how a liquid forward market can be established within an environment where scheduling uncertainty of conventional plant is increasing and financial institutions are withdrawing from the financial derivatives markets (for both power and commodities) as a consequence of increasing financial regulations (e.g. EMIR);
- (ii) Designing specific Market Power mitigation measures for each of the different trading timeframes;
- (iii) Ensuring the sustainability of the market for generators (and ultimately customers) by ensuring the total remuneration of generation will provide a reasonable return to enable them to finance

their activities. This needs to look at all the revenue streams including DS3; and

- (iv) A greater assessment of the relative costs of the options which must also include the general costs of establishing and trading in the market (for the TSOs, MOs and participants) but which must also consider wider financial resource requirements including working capital, credit collateral and currency exposures for NI participants.

The Energy Market options

PPB's assessment of the energy market options is that Option 1 is the best market model for the I-SEM. It is the simplest form of market and it reflects the market form that prevails in GB and most of the rest of the EU and therefore will be Target Model compliant. This alignment means it is also likely to be at least risk of requiring further reform.

Market power mitigation measures will be required but that is the case for all the options. A benefit of Option 1 is that the mitigation measures can be more targeted than for example is the case in Option 3 where all parties are explicitly mandated to participate in the DAM. This targeted approach would be similar to the approach taken by Ofgem within the GB market, for example in relation to its "Secure and Promote" licence conditions. It also makes it easier for the obligations to be relaxed should dominance reduce.

Option 1 provides the scope for greater flexibility to enable market participants to manage their risks and the ability to self-schedule is likely to increase liquidity in the forward market by removing the risk of scheduling uncertainty.

The ability to establish forward bilateral contracts will also reduce the reliance on the Euphemia algorithm which, as we discuss in more detail below (and which is also addressed in the paper produced by Baringa for Viridian Group upon which we draw), would create a material risk that it may not be able to determine a coherent or feasible schedule for a small market that doesn't have a lot of flexible capacity (such as the Hydro in the Iberian market).

Without any pre-committed volumes, generators in the SEM are likely to seek to utilise sophisticated bids with multiple conditions to seek to reflect the underlying commercial and technical capabilities of their generating units but if the bids were restricted (as they are by some exchanges) then the solution determined by Euphemia may not be an efficient one and the "all or nothing" nature of the sophisticated bids may also result in inefficient and unpredictable outcomes. Such risk would also materially impact the forwards market.

Reliance on Euphemia for the sole determination of the local market schedule also introduces an unquantified risk as Euphemia's governance arrangements may have limited or no accountability to customers in Ireland. Similarly, Option 3 requires exclusive reliance on an as yet unspecified shared order book arrangement which is also a risk.

PPB's preference is therefore for Option 1 with clear market power mitigation measures defined as part of the HLD, particularly to provide for forward market liquidity. It will also be important that the SEMC does not select an option not currently consulted upon as its preferred HLD without further consultation on that new option such that stakeholders can provide appropriate considerations.

1. Introduction

Power NI Energy – Power Procurement Business (“PPB”) welcomes the opportunity to respond to the consultation paper on the High Level Design (HLD) for the Integrated Single Electricity Market (I-SEM) for Ireland and Northern Ireland.

In PPB’s consideration of the matters raised in the consultation paper, PPB has, with regulatory consent, drawn upon external consultancy advice provided by Baringa and NERA to the Viridian Group to help the business develop an understanding of the options and to draw on their knowledge of the experiences of different market designs in other worldwide markets. Baringa and NERA have provided Viridian with a number of expert reports on key areas of concern that were identified to be critical to the decisions to be taken in relation to the HLD and we make reference to those reports in this submission.

2. General Comments

The current drive towards efficient utilisation of interconnectors arises from the requirements of the various Network Codes and particularly the code relating to Capacity Allocation and Congestion Management (CACM). Since the design and implementation of the Single Electricity Market (SEM) significant changes have happened in European and national energy markets:

- The Third Package, which came into force in September 2009, aims to further liberalise European Energy markets. Co-operation between the TSOs was established through the establishment of the European Network of Transmission System Operators for Electricity (ENTSO-E). The Third Package created a regulatory framework to support a single, European Energy Market by developing EU-wide Network Codes. These codes form a legally binding set of common technical and commercial rules and obligations that govern access to and use of European energy networks.
- The UK government has committed to source 15% of the UK’s energy requirements from renewable sources by 2020. The NI Executive has gone further and matched the ROI Government’s target of sourcing 40% of electricity from renewable sources by 2020. Progress towards meeting these targets has been significant. The power system is currently operated at a maximum SNSP (System Non Synchronous Penetration) level of 50% in real-time. However, in order for the System Operators to achieve the 40% RES-E targets by 2020; the system will need to be operated in real-time with SNSP levels of up to 75%. These targets therefore present material technical and commercial challenges which will require suitable market arrangements to ensure appropriate investments are made and ensure security of supply.
- Demand side response programmes have begun to emerge across the EU in recent years. The gradual rollout of smart metering systems, the development of network codes for the internal electricity market (particularly those on demand connection, system operation and

balancing) could, over the next decade, have a significant impact on the all island energy market.

- The all island electricity system has benefited from greater interconnection with Great Britain with the commissioning of the East West Interconnector.

PPB therefore welcomes the review of SEM as an opportunity to optimise the market arrangements taking cognisance of the changes and challenges which have happened since 2007 and to ensure SEM complies with the EU Target Model. It is important that the reforms work in the overall interests of consumers and markets participants on the island of Ireland. Hence the I-SEM must ensure that not only is interconnector trading efficient but that the local electricity market continues to operate effectively. and provides a sustainable wholesale market framework that provides reasonable returns to investors and market participants and delivers competitive prices and a secure and reliable supply of electricity for consumers.

In Northern Ireland the Strategic Energy Framework (SEF), published by the Department of Enterprise, Trade and Investment (DETI) in 2010 and endorsed by the Assembly Executive recognises the importance of energy costs in NI, and highlights that:

- “It is imperative that any policy decisions made now are assessed for their impact on energy costs”;
- “It is also important to ensure that policy changes which could impact on energy costs do not have an adverse effect on business competitiveness”, and
- “As Northern Ireland has the highest levels of fuel poverty in the UK we must ensure that our desire to develop a more sustainable and secure energy supply is not detrimental to energy consumers”

PPB therefore fully supports the objective of the I-SEM to optimise the utilisation of interconnection as it will help minimise costs for customers As renewable penetration increases the optimisation of interconnector trading becomes increasingly significant.

PPB believes it is imperative that I-SEM ensures that the generation which is required to ensure security of supply for consumers is appropriately remunerated. The changes which have occurred since the introduction of SEM, outlined above, and most significantly as a consequence of Government policies to produce 40% of electricity consumption from renewable sources by 2020, are beginning to have a material impact on the load factors of conventional generation and overall market revenue adequacy which must be addressed by the new arrangements. PPB believes the current form of the CPM must remain as a keystone of the new market arrangements in I-SEM along with complimentary energy and ancillary service markets.

2.1. Evaluation and Scope of the HLD

The evaluation criteria against which the HLD options will be assessed were confirmed in the Next Steps Decision Paper (SEM-13-009). They retain the same criteria that were applied to the original SEM design with the addition of ensuring the design efficiently implements the EU Target Model. PPB considers that these are valid considerations against which to assess the HLD options although we are concerned that the SEMC should not seek to confine the assessment narrowly but must consider the totality of the “electricity market” that impacts customer prices and which spans from the forward market through to real time dispatch.

PPB has a number of concerns with the narrowness of the approach adopted in the consultation paper and believes there are additional factors that must inherently be included in the assessment of the HLD. These additional elements include :

1. Ensuring an effective forward market (given this is the market that sets the price for most customers);
2. Market Power mitigation (including market making obligations) in each of the market timeframes (from forward through to balancing);
3. Ensuring that the total remuneration of generators from energy, capacity and ancillary service revenue streams is reasonable (as noted in paragraph 10.2.1 of the consultation paper but not at any stage considered); and
4. Considering participation costs, including the working capital and credit cover collateral required under each of the Energy and CRM options.

We comment on each of these below.

2.1.1. The importance of the Forward Market

The ability of market participants to manage risks is critical to the effective functioning of a market. Suppliers require forward contracts to match with the desire of most customers for a fixed price product. Therefore generators and suppliers should have an alignment of objectives to remove the volatility that exists in spot markets. However, as is highlighted in the Baringa report on Forward Liquidity and Market Power Mitigation¹, forward market liquidity has been an issue in many markets but is a particular issue in the current SEM and therefore the issue needs to be carefully considered as an integral element of the I-SEM high level design.

Output uncertainty is inherent for intermittent wind generators and this is increasingly impacting the scheduling uncertainty for conventional generators. With energy policy seeking to achieve higher levels of renewable generation, this uncertainty will continue to grow putting further pressure on the potential forward market commitments that can be made by mid-merit generators. It is important that this is carefully considered to ensure that the HLD design maximises the scope for liquidity in the forward timeframe.

¹ Baringa paper titled “Promoting forward market liquidity and mitigating market power under the I-SEM

It is also worth noting that obligations in financial legislation, such as those imposed by EMIR, are driving financial counter-parties out of commodity markets. This not only means that these financial players (e.g. Deutsche, Bank of America/Merrill Lynch, JP Morgan) are no longer trading directly in power markets but they are also no longer willing to trade in fuels and carbon and therefore the pool of potential counter-parties willing to conclude commodity hedges with generators to back up their forward electricity trades has reduced significantly. The gas market is much more liquid than the power market in GB, owing to the NBP's status as a European hub. This means that any remaining financial intermediaries interested in trading GB energy fundamentals will naturally focus on the gas market. It is therefore important to ensure the I-SEM market arrangements are complimentary to the GB gas market.

The changes in risk appetite of financial institutions for non-core markets like commodities needs to be recognised when considering how best to ensure liquidity in the forward markets.

The EMIR legislation differentiates between financial and non-financial counter-parties with the classification based on the notional value of financial derivatives held by a party. Any future classification of I-SEM participants as financial counter-parties could have material cost implications for customers, for example where clearing obligations are imposed, which could have a material impact on liquidity. The SEMC should investigate these issues and the impact they may have on the market options prior to making a final HLD decision.

2.1.2. Market Power mitigation

While market power is recognised as an issue throughout the consultation paper, it is deemed to be an issue that can be addressed as part of the detailed design. However, we consider that the issue is so material that it may be too late to address it at that stage and we believe the issues need to be carefully considered and addressed at the HLD stage.

Market Power is a concern that will affect the functioning of the market under each of the proposed energy market options but it is likely to be subtly different in each. Similarly, it is a significant risk to the operation of the different CRM designs.

Its impact must therefore be fully incorporated alongside the assessment of the energy and CRM options to ensure the determined HLD is fully capable of operating effectively recognising the level of market power that exists and that the measures employed to manage and mitigate that power do not then create unexpected outcomes in the energy and capacity markets (and perhaps the ancillary service market).

2.1.3. Ensuring the Total Remuneration of Generation

If the electricity market is to be sustainable, it must ensure that the generation that is required to ensure security of supply for consumers is appropriately remunerated. There have been significant changes in the wholesale markets since the SEM was designed, primarily as a consequence of Government policies to produce 40% of electricity consumption from renewable sources by 2020. This ambitious target is supported by different renewable support

schemes in Northern Ireland and in Rol and the growth in output from renewable sources has had a significant impact on the load factors of conventional generators over the last few years and has resulted in a much flatter price duration curve since the mid-merit plant are largely CCGTs with similar thermal efficiencies and hence generation costs.

The consequence is that these units are no longer earning sufficient inframarginal rents to remunerate their investment. This feature is not unique to the SEM but is also evident in GB where spark spreads are low and similarly in other parts of Europe (which is also driving the review of energy markets and the move to implement CRMs). This is not a sustainable outcome and the design of the I-SEM provides an opportunity to ensure generation is earning a reasonable return on their investments from the totality of their revenue streams, comprising energy, capacity and ancillary service revenues.

The SEMC recognised this requirement in the Next Steps decision paper and also re-state it in the consultation paper (paragraph 10.2.1). However the consultation paper seeks to address the energy market and the CRM options separately and totally ignores the DS3 workstream. These three revenue streams must be considered in totality to ensure aggregate revenues will sustain investment in the generation that is needed to enable the renewable targets to be met and to ensure the long term sustainability of the market and security of supply for consumers. The overall market arrangements must ensure that flexible generation, which may not be the cheapest, is sufficiently remunerated.

2.1.4. Assessment of costs including costs of participation

The consultation paper does not tangibly address the cost of operating the various market options and there is a vague commitment to conduct a Cost Benefit Analysis on the preferred option which may be included along with the draft decision. There are likely to be significant costs for the TSOs and the MO in operating each of the markets and there is no indication of whether there is likely to be any material differences in the costs to implement each of the options. There will also be costs for participants that could be significant and it will be important to assess these costs and ensure they are minimised.

In addition to system and internal operating costs, a key concern must be the impact of each of the options on working capital requirements and on the collateral required to provide credit cover. For example, we understand the DAM requires next day settlement which would result in a significant advancement in cash settlement for participants compared to settlement in the SEM. This will be welcomed by generators but adds significantly to the working capital requirements of suppliers and should be a significant factor in the assessment of Option 3 which mandates participation in the DAM and requires unitised bidding.

Similarly, the DAM and IDM markets trade in Euros and therefore participation in these markets would seem to enforce currency exposure on Northern Ireland participants. Where participation is voluntary then the participants can select whether to participate and manage this exposure whereas where participation is mandated, the participants are forced to incur such costs.

2.2. PPB's assessment of the HLD options

Review of the options highlights that Option 1, which places an undefined limit on forward bilateral trading leaving the residual volumes to participate in the DAM and IDM markets, could be considered a less extreme version of Option 3 which effectively defines the bilateral trading limit at zero and requires the residual (i.e. 100%) to be traded in the DAM. Hence these options could be viewed as being related.

We set out our views on each of the options below.

Option 1: Adapted Decentralised Market

PPB considers that this option is the most consistent with the bilateral markets that operate in the rest of the NWE region which should mean that it is certain to be compliant with the target model and is also likely to be exposed to the least of further requirements to modify the design.

It is also the purest and simplest form of market structure and this simplicity should promote liquidity, make it easier for potential new entrants to understand the market dynamics, and it should also be easier for customers to understand and interact with. This commonality with the larger markets in NWE will also make investor engagement easier.

The market also offers the most flexibility for participants to trade and from a generator's (or generation intermediary/agent's) perspective, it places greater control in the hands of the trader over the operation of the generating units at their disposal. This will enable generators to trade in the forward markets and possibly over longer horizons than is currently possible in the SEM which we believe will improve liquidity in the forward markets.

Participants will be incentivised to trade in the DAM and IDM market to capture any efficiencies that can be achieved (e.g. from lower cost offers in the market including from wind as its volume firmness increases closer to real time). In addition, when the FIT CfD scheme is introduced in Northern Ireland, generators will have a natural incentive to sell their volumes in the reference markets (to capture the reference price of their CfDs), and suppliers will have a natural incentive to buy volumes from these markets (to hedge the volatility in their CfD payments).

This HLD should therefore naturally be the most sustainable market model and this would be the case in a situation where the market is competitive. However in Ireland, it is currently the case that the market has a dominant generator and a dominant supplier. As we noted earlier, such market power will be an issue for whatever market design is adopted and therefore market power mitigation measures will be required regardless of the HLD selected. Given this constraint, it would therefore seem logical to adopt the best market design and to then implement appropriate measures to ensure market power cannot be exercised to distort the efficient functioning of that market. We stress however, that the design of these measures must be completed as part of the HLD to ensure the measures are coherent and will work effectively to deliver the correct outcomes.

A further benefit of this approach is that the market power mitigation measures can be relaxed or strengthened by the SEMC as necessary as market shares and levels of dominance change.

In relation to the Adapted Decentralised Market, we consider that the market power measures that would need to apply includes imposing a requirement for dominant generators and suppliers to have market making obligations in the forward market and with further requirements to create liquidity (e.g. an obligation to trade all un-contracted generation or demand volumes on a unitised basis) in each of the DAM, IDM and balancing markets.

These latter measures largely replicate the implicit but non-targeted measures inherent in the Mandatory Centralised Market (Option 3) but under Option 1, it provides additional flexibility to enable the SEMC to focus the market power mitigation measures to best address the dominance issues prevailing at that time and therefore, as we noted earlier, would allow the measures to be amended as the market evolves. In addition, it is not wholly reliant on the Euphemia algorithm to determine the baseline schedule for the I-SEM and therefore mitigates the Euphemia risks that are noted later in this response.

The Baringa report on Forward Liquidity and Market Power Mitigation² provides a more detailed assessment of the issues and possible the various possible mitigation measures in greater detail.

A final issue relates to the pricing in the balancing market. The proposal is that bids will be based in Incremental and Decremental prices. We understand these prices will be used for balancing actions and will also be used by the TSOs to manage constraints. The TSOs dispatch instructions for system management are likely to extend beyond simple incremental or decremental instructions and are likely to at times require that generating units start up or close down. It is not clear if it is proposed that such costs are to be settled separately or whether the Inc and Dec price/quantity pairs can accommodate P/Q pairs that are not monotonically increasing. An alternative approach may be to provide for the submission of start and stop costs. This will need to be addressed as part of the market design.

² Baringa paper titled “Promoting forward market liquidity and mitigating market power in the I-SEM

Option 2: Mandatory Ex-Post Pool for NET Volumes

While this market design has the same advantages as Option 1 in relation to the flexibility conferred to participants in the forward timeframes it operates a Pool in parallel for balancing. This hybrid is likely to be the most complex of all the options to operate and because of the effective requirement for two parallel trading systems is likely to be the most costly to operate in terms of central systems, participant systems, etc. This therefore seems to combine “the worst of all worlds”.

The market would appear to provide a benign route to market for intermittent generation who could delay participation until the balancing net pool market. However, this could distort market coupling and result in inefficient cross-border trades and could lead to higher levels of curtailment or increase the cost of real-time constraints as the TSO seeks to unwind interconnector flows that were established in the earlier timeframes.

The practicality of the HLD is therefore highly questionable and this seems to be borne out by the fact the net complex pool concept is untested and that there is no international precedent for this market design.

PPB does not therefore consider this option to be viable.

Option 3: Mandatory Centralised Market

This option represents a transition of the current mandatory ex-post market to a mandatory ex-ante market, concentrated at the day ahead stage. This will ensure liquidity in the DAM and should provide the scope for efficient market coupling and because of the concentration should ensure there is a reliable reference price for financial contracts.

While these are positive aspects of the proposed design, there are a number of significant risks with the proposition. The market is not as simple as a bilateral market and relies on a complex algorithm to schedule the market which may be difficult to replicate in a model and which will therefore make it more difficult to engage with customers and investors.

The market relies fully on Euphemia to determine the market scheduling (and market pricing). However while the Euphemia algorithm has been developed to accommodate the sophisticated bid structures previously used in the Iberian market, it is not clear how coherent or feasible the results might be when applied to a smaller market where the minimum generation levels of generating units are high relative to demand and where intermittent generation is targeted to meet 40% of electricity demand by 2020.

The current SEM requires complex Commercial Offer Data and utilises detailed Technical Offer Data. It is likely all generators will seek to employ sophisticated bid structures with multiple conditions to seek to accurately mirror their underlying Commercial and Technical capabilities. Our experience and understanding of despatch algorithms is that adding layers of complexity and conditionality will undoubtedly either extend the solution time to reach the minimum cost solution or have to compromise on the solution to enable the algorithm to conclude within the imposed time constraint (see sections 3.3 and

3.4 of the Baringa report³ that provides Background on Option 3). We have major concerns that this creates a significant risk to the viability of this option and there is a high risk that inefficient or unpredictable schedules and prices could emerge from such reliance.

Section 2.2 of the Baringa report³ also highlights that the Iberian market is much larger (and therefore individual generator size is much less material), has a much more diversified plant mix (and therefore a more distinct cost duration curve within which CCGTs capture a much smaller market share), and has significant hydro capacity which offers significant flexibility to provide a feasible schedule. In addition, the Iberian market does not mandate participation. These features mean that there is much less risk to the delivery of a feasible schedule for the Iberian market than there will be for the Irish market.

We also have a concern that the proposition is for trading to be “Exclusive” in the IDM. This trading platform is as yet undefined and there is high risk from committing to such a platform without understanding whether it will meet the requirements of the I-SEM. We would therefore suggest that it would be better to allow flexibility for participants (again we would suggest this should be limited to non-dominant generators/suppliers) to trade bilaterally within day to manage their supply and demand risks.

The DAM participation obligations on wind generation and demand are unclear under Option 3. Conventional generation is mandated to participate in the DAM but the obligations on wind generation and demand is contradictory. Paragraphs 8.3.4 and 8.3.5 of the consultation paper describe participation as mandatory but on a “best endeavours” basis, while in Figure 12, demand participation is shown as voluntary. There is a risk that if there are skewed obligations with conventional generators mandated, that they could be exposed to price uncertainty and distortion. Given day ahead uncertainty, wind generators may be incentivised to understate their output expectations. From a supplier perspective it may always be advantageous to understate demand since that would tend to reduce the clearing price.

This mandated participation could also have implications for the efficiency of coupling since the I-SEM traders would be mandated whereas the GB traders would be able to select how they participate which may enable them to cherry pick to their advantage.

The same issue as outlined above for Option 1 in relation to the form of balancing market bids would need to be addressed under Option 3 (i.e. bids are used for both balancing and management of the system and constraints which may require more than just incremental or decremental movements).

³ Baringa Report titled “I-SEM HLD Consultation: Background paper on Option 3”

Option 4: Gross Pool - NET Settlement Market

On a superficial level, Option 4 may appear to represent the least change from the current SEM but PPB has concerns that the model is not compliant with the requirements of the Target Model.

Notwithstanding that hurdle, PPB has major concerns that the design is discriminatory as it confers firmer status to counter-parties to trades in the DAM and IDM markets than is provided to indigenous generators who participate in those markets. I-SEM generators would receive a financial CfD which has inherent risks because the generator may not be scheduled in the ex-post market but would have taken on a financial exposure by successfully participating in the ex-ante markets. Meanwhile counter-parties in GB will have struck a firm physical trade and suppliers in the I-SEM will effectively have struck a firm bilateral trade (provided they are not contracting for levels close to their marginal demand).

This skewed trading incentive is likely to result in generators who are uncertain of being in the ex-post schedule (e.g. intermittent wind and mid-merit generators who are balancing wind and demand volatility) deciding not to participate in the ex-ante markets to avoid taking on additional risks. This exclusion may also distort the market coupling process and could result in distorted pricing and inefficient cross-border energy flows. This problem is also likely to get worse as scheduling uncertainty will inevitably increase as the installed wind capacity increases. Such an outcome would be contrary to the objectives of the Target Model.

The scheduling risks with an ex-post pool are also likely to inhibit participation in the forward market and the increasing uncertainty arising from growing wind penetration is likely to put further pressure on forward market liquidity.

As we noted earlier, it is questionable whether this HLD is compliant with the Target Model, and it must also carry the greatest risk that the evolution of the EU target will require further substantive change much sooner than would be the case for the other options.

PPB therefore considers this option to be unattractive and not a viable HLD.

2.3. The requirement for a Capacity Remuneration Mechanism

PPB considers that a Capacity Remuneration Mechanism (CRM) is essential in a small market such as exists in Ireland. This was recognised during the design of the SEM, and has been confirmed as a critical market design feature at various stages since⁴.

The features that underpinned the need for a CRM in the SEM continue to affect the market and they continue to provide justification for the requirement for a CRM in the I-SEM. The features include,

- the small size of the Irish market;
- the capacity increment from an efficient new entrant generator is large relative to the peak demand in the SEM and is equivalent to four to five years of demand growth and therefore entry overwhelms the entry signal;
- the impact of inappropriate entry and demand shocks are significant and are magnified in a small system;
- there is a dominant incumbent in the SEM with market power; and
- there is a substantial risk of regulatory and/or political intervention and it is unlikely that the price volatility that would be required in an “energy only” market to remunerate investments would be acceptable.

The requirement is further bolstered by the EU and Government’s low carbon objectives which have resulted in significant support mechanisms for renewable generators but which are resulting in major reductions in the load factors of conventional generation which is still required to meet demand when the wind isn’t blowing. This has had a very material impact on the revenues of conventional plant and particularly mid-merit capacity that is rarely capturing Infra Marginal Rent when it is generating. This is not unique to Ireland and is the major driver behind the recent decisions of many EU countries including those in NWE (Germany, France, GB etc.) to explore the implementation of CRMs.

Furthermore, Ireland has extremely ambitious renewable targets and this ambition will further exacerbate the reduction in load factors and revenues.

PPB believes that there is an absolute requirement for a CRM and that this is capable of being demonstrated to be in compliance with the EC’s draft guidance on generation adequacy and state aid. This view is supported by the attached NERA report⁵ that was produced for the Viridian Group and which presents NERA’s assessment of the case for a CRM in Ireland taking account of the specific market conditions and the wider requirements including the EC’s guidelines.

⁴ In the RAs Medium Term Review decision published in March 2012 and in the Next Steps Decision Paper in February 2013

⁵ NERA Report titled “The Capacity Remuneration Mechanism in the SEM”

2.4. PPB's Assessment of the presented CRM Options

It is difficult to provide a definitive assessment of the options presented as many of the options require substantially more definition before a full evaluation and assessment could be concluded.

PPB's high level views on the options as currently described are set out below and the options are assessed against PPB's view that the objective of the CRM is to ensure generation adequacy by providing a more stable revenue stream that enables generators to secure a reasonable return on their investments and which minimises regulatory risk. The NERA report sets out further detail and provides NERA's assessment of the options, particularly in the context of minimising regulatory/political risk and the effect on cross-border trading.

Option 1: Strategic Reserve

PPB does not consider that a targeted Strategic Reserve mechanism will address the fundamental objectives of the CRM and will therefore not be successful without further intervention. We believe that a Strategic Reserve mechanism would block any other investment and would become the route to market for all generation and hence will enshrine the "slippery slope".

Option 2A: Long Term Price Based CRM

PPB considers a long term price based CRM will meet the objectives and can be designed to ensure cross-border trade is not distorted (e.g. by excluding interconnectors from payments in common with what is proposed for GB) and by ensuring short term prices can increase in the same manner as they will in GB to ensure cross border trading continues to be efficient.

A concern with the current CRM in the SEM is that the exit signal is weak which has resulted in over-capacity. The current design does include the demand curve such that payments have fallen as capacity has increased and which has resulted in current payments being reduced to c65% of the BNE price although capacity is still not exiting. This may be a manifestation of market dominance but PPB considers this feature could be overcome in the I-SEM and therefore should not present a barrier to the continued utilisation of the current form of CRM.

Option 2B: Short Term Price Based CRM

PPB does not consider that a volatile ex-post short term price based CRM will address the fundamental objectives for the CRM. The very nature of concentrating payments into periods where capacity is scarce effectively replicates an energy only market and therefore recreates the problems the CRM is to be designed to overcome. PPB does not therefore consider this option to be viable.

Option 3: Quantity Based Capacity Auction

PPB considers a capacity auction could be designed but there are significant difficulties to overcome. The natural capacity increment is significantly larger than the annual increment in peak demand and hence following new entry, the prices in a capacity auction could be depressed for a number of years. This option therefore suffers from the problems the mechanism is trying to overcome

and the risk is that generators will delay investment until they can be sure that their entry will not deplete the capacity price in the margin to unsustainable levels. This can only mean that security of supply will be reduced for customers.

The other major concern with this option (and which is common to all the quantity based options) is the consequences of market dominance on the auction prices. A dominant generator with deeper pockets than its competitors could depress prices (or merely threaten to) resulting in the exit of competitors. There would therefore need to be market power mitigation measures applied to ensure any such market power cannot be exploited. This would need to apply to both the primary auction and to the secondary market in which smaller participants would be seeking to manage their capacity risks when, for example, they are on an outage. The oversight of such market power would also create a new layer of regulatory risk for generators that would need to be considered during more comprehensive consideration.

Option 4: Quantity Based Capacity Obligation

PPB considers this design option suffers from the same issues as centralised capacity auctions. In addition, it would create an additional burden on suppliers as they would need to be continually refining their position to ensure it aligns with their retail market share. This would require a liquid market in such obligation certificates which may be difficult to create in a small market and which may be exacerbated when vertical integration would confer benefits to those market participants. This option has some additional issues that would also need to be addressed including, retail market power, the potential for additional collateral costs and whether the obligation would be a barrier to entry into the retail market which would be detrimental to competition.

PPB does not consider this option to be viable.

Option 5A: Centralised Reliability Options

This option appears to operate as a one way CfD with a strike price referenced against the energy market. It is not apparent how these options would be valued and they would need to be overlaid against an energy only market that would allow prices to rise to VOLL. This would therefore rely on no intervention or price capping since otherwise the option fee would be reduced and the remuneration for generators would be diluted in the same way as intervention in an energy only market creates the “missing money” problem.

Similarly, the option price is likely to collapse following new entry as the probability of high spot prices reduces and hence revenue volatility would remain. There is also a risk that the market price could exceed the CfD strike price even though a generator was available but not in the schedule which could create a significant exposure for that generator. Finally, if the CfDs were to be auctioned then market power would again be an issue that would require mitigation measures to be adopted.

PPB does not consider this option to be viable.

Option 5B: Decentralised Reliability Options

PPB considers this option has the same issues as the centralised reliability option with a number of additional problems. Decentralising the obligation adds retail market dominance as an issue that would require mitigation measures to address and similar to the Capacity Obligation CRM, creates an additional trading and risk management burden which may be a barrier to entry for new retail market participants. The option is also likely to confer benefits on participants who are vertically integrated which would also make market liquidity difficult to achieve.

PPB does not consider this option to be viable.

3. Response to the Specific Questions

1. Which option for energy trading arrangements would be your preferred choice for the I-SEM market, and why?

As we discussed in the main body of this response, PPB does not believe Option 2 is a viable option. We also consider that Option 4 would discriminate against I-SEM generators and is unlikely to result in efficient cross-border trading as generators in the market are likely to be reluctant to trade in the DAM and IDM markets because of the additional risks they could be taking on if they are not scheduled. In addition there is a risk that the model may not be complaint and even if it were, there is a greater risk that further development of the Target Model could require further change to Option 4 within a short timeframe.

Option 3 does concentrate liquidity in the DAM but we have significant concerns with the mandated reliance on Euphemia for the scheduling of the whole I-SEM market. As no generators have any level of self-scheduled commitment we would expect most generators to rely on sophisticated bids with multiple conditions to seek to replicate as accurately as possible the commercial and technical capacity of their generating units. This may prove to be a much more complex scheduling problem to solve for a small market than the algorithm has to address in other markets and as is cautioned in the Baringa⁶ report, limits on the extent of complex orders (as has been applied in other markets) could be imposed which may then result in inefficient and unpredictable generation schedules and market prices.

The reliance on the Euphemia algorithm also means the SEMC will very limited influence on the governance of the ongoing development of the algorithm which would be a risk for the I-SEM. There is also some doubt over mandated participation obligations on wind and demand and this uncertainty (or levels of discretion) in relation to participation could result in distorted prices and cross-border flows.

Our conclusion is that there are significant risks with Option 3 and it is a more difficult market to understand and it will also be difficult to explain its outcomes to customers and investors.

Option 1 is the simplest market form and reflects the normal market design in the rest of the NWE region. It provides the most flexibility to participants and is the easiest to explain to customers and investors. We believe the market will increase forward market liquidity and will also incentivise trading in the DAM and IDM as generators seek to capture the benefit of any opportunities that materialise closer to real time as potential wind generation output firms up or from market coupling.

As is recognised in the consultation paper (and in the Next Steps decision paper), market power is an issue for any market design. In relation to Option 1, we believe these should be addressed as part of the HLD and measures can be determined to ensure dominant generators cannot exercise their market power and ensure that there is liquidity in each of the market timeframes by

⁶ Baringa report titled "I-SEM HLD consultation: Background paper on Option 3"

imposing market making obligations and market participation obligations on participants with market power.

With such market power mitigation measures incorporated at the HLD stage, PPB believes Option 1 is the best HLD option. It has the same underlying design as the other markets in NWE that the I-SEM will be coupling with and is fully IEM compliant and we believe it can provide the highest levels of liquidity, particularly in the forward market while incentivising active participation in the DAM. It has the additional benefit of providing the SEMC with the opportunity to adjust the market power mitigation measures as market conditions allow and does not risk full reliance on Euphemia which could be unpredictable when trying to schedule all the generation in the I-SEM from a zero base.

2. Is there a requirement for a CRM in the revised HLD, and why?

During the design of the current SEM, it was clear that a CRM was a necessity to reduce investment risk due to :

- the small size of the Irish market;
- the size of an efficient new entrant generator relative to the peak demand in the SEM which means it takes a number of years demand growth before the entry no longer overwhelms the entry signal;
- the risks from inappropriate entry or demand shocks that are magnified in a small system;
- the risks from market power from a dominant incumbent in the SEM;
- energy market prices would be exceptionally volatile in an “energy only” market which would increase the risk of business failure; and
- the risks of regulatory and/or political interference in an “energy only” market to place caps on energy prices that would need to rise to the level of VOLL for an average of eight hours per annum to remunerate investments.

These features remain relevant today and there is hard evidence of the concerns being realised such as from (i) the demand decrease that has resulted from the global financial crisis, (ii) new entry even where there is surplus capacity, (iii) Increased interconnection, (iv) political intervention in external markets impacting on interconnector flows (e.g. the carbon price floor), and (v) consultation on regulatory intervention to resolve a capacity risk in Northern Ireland notwithstanding the TSOs’ analysis indicates there will be a capacity surplus relative to the required Generation Security Standard.

Furthermore, the increasing penetration of intermittent renewable generation has changed the paradigm for wholesale electricity markets and the load factors on conventional generation are declining. This change is now evident across the European markets and there is an ever increasing realisation across the EU that the wholesale markets are unsustainable in the absence of a CRM. The wind penetration in Ireland is also driving changes to the technical requirements for generators that is more onerous than will be required in other countries, for example in relation to RoCoF.

These problems are all magnified in a small market that has ambitions to be at the leading edge of wind penetration and therefore a CRM is an essential component for the I-SEM.

3. *If there is a requirement for a CRM in the revised HLD, what form would be your preferred choice for the I-SEM, and why?*

We procured independent advice to assist our understanding of the CRM options and to help us assess which option is likely to deliver against the fundamental objectives of the CRM in a sustainable manner.

PPB's conclusion is that the best option is a long term price based CRM (i.e. Option 2A) which is similar to the existing capacity mechanism in the SEM. We would highlight that the current model is not purely price based and capacity is a feature in the derivation of the capacity pot and the remuneration increases or decreases at a modest rate (i.e. avoiding sudden volatility) depending on the capacity available at that time.

PPB considers that the Strategic Reserve proposition (Option 1) will inevitably distort the market since it does hold back capacity from the market and in a small market it would inevitably be the only means of attracting new capacity and hence succumb to the "slippery slope syndrome".

PPB considers that the Short term price based mechanism (Option 2B) exhibits the same problems as an "Energy Only" market in that by seeking to reward capacity at times of shortage, prices will inevitably be volatile and hence this does not address the objective of reducing volatility for investors. This type of CRM would also need to address market power issues which were issues encountered in the England & Wales pool.

PPB considers the Quantity based options all suffer from a significant market power threats and would require very strict market power mitigation measures that are likely to create a high regulatory burden and, given that resources need to be managed, it would be better to focus on the delivery of liquid forward, DA and ID markets. In addition, the prices in these options are likely to be volatile because the capacity increment of an efficient new entrant would depress prices for a number of years.

We do not see any value in the decentralised options (Options 4 and 5B) which merely serve to introduce further trading burdens for suppliers and indeed may represent a barrier to entry for small suppliers which could diminish the scope for retail competition.

Similarly, PPB considers there is a real risk that options (Options 5A and 5B) will not attract investment as the remuneration depends on one-way CfDs which would create payment risks for a generator that is not scheduled notwithstanding capacity margins may be tight for a period. This market construct does not appear to be operating in any other market and it would seem extremely risky to trial such a regime in the I-SEM that has the distinct features already described in our answer to question 2 above (small system, large units size relativity, market dominance, high intermittent generation penetration, etc.).

Topics for the High Level Design of Energy Trading Arrangements

4. Are these the most important topics to consider in the description of the HLD for the revised energy trading arrangements for the single electricity market on the island of Ireland?

The topics considered address the two largest design elements that need to be assessed. However, in order to ensure the long term viability and sustainability of the I-SEM, the total remuneration of generation must be properly considered. Hence it will be impossible to opine on the suitability of a HLD that does not describe and enable assessment of the full scope of revenues for generators. This is required to enable confirmation that the market (in its entirety) will provide a reasonable return for generators, thereby ensuring security of supply for consumers at sustainable prices. The absence of any meaningful integration of the DS3 workstream creates a significant risk that the overall design will not be sustainable or will require “fixes” which would only serve to increase regulatory risk. Therefore we believe Ancillary Services needs to be included in the assessment to ensure the final HLD is coherent and sustainable.

The other key consideration that must be assessed at the HLD stage relates to Market Power mitigation measures and Market Making obligations as these are critical to the overall success of the market and must be given its due consideration at this stage rather than waiting until the detailed design stage at which point it may be more difficult to mould solutions within constraints imposed by the HLD. It would be better to design how market power will be mitigated and how the forward market (which is the most critical market for customers) can operate effectively.

5. Are there other aspects of the European Internal Electricity Market that should form part of the process of the High Level Design of energy trading arrangements in the I-SEM?

Other EU Network Codes are at an earlier stage of development and the HLD must be flexible enough to be able to adapt to subtle shifts in the evolution of these codes, e.g. the Balancing Code. There is also significant reform planned for the gas sector and there is a real danger that limitations imposed by the gas networks could frustrate the realisation of efficient outcomes in the electricity markets (although there now appears to be some recognition of the impact of low carbon investments of the gas markets and networks at an EU level).

It is also critical that the reform of the electricity and gas markets are complementary such that there is flexibility within the gas arrangements (e.g. in relation to short term gas capacity products) to facilitate flexibility in the electricity markets that is needed to support the desired growth in renewables

It will also be important to recognise the increasing impact of financial legislation on energy markets with potential clearing obligations and the continuing contraction of the pool of trading counter-parties for financial derivatives.

Summary of the options for Energy Trading Arrangements

6. What evidence can you provide for the assessment of the HLD options with respect to security of supply, efficiency, and adaptability?

It is impossible to comment on any individual HLD option with respect to long term Security of Supply without considering the complete remuneration framework and whether that will be sufficient to remunerate the changing plant portfolio that is needed to support government policies in relation to renewable penetration.

In relation to operational security, it appears that the TSOs have finally accepted that they will retain control of despatch in real time and that while each of the HLD options may initially provide a different starting point, the TSOs will have the tools available to enable the safe and secure operation of the system.

In relation to efficiency, economic logic would suggest that each of the market designs should tend towards the same outcome. There has always been some concern that a bilateral market would for some reason be less efficient but commercial logic would suggest that generators would trade between themselves where a cheaper source is available to minimise costs. Therefore, unless there is a particular reason why generators are not taking advantage of mutually beneficial trades (which may be due to some exercise of market power), a bilateral market should seek the most efficient outcome in the same manner as a strict merit order would.

We consider that Option 4 will not result in efficient cross-border trading because of the risks imposed by the DAM and IDM being a financial market for generators in the I-SEM (note suppliers are not exposed to scheduling risk, as a CfD does not result in the same exposure for suppliers). This disincentive to generator participation may result in inefficient cross-border trades due to the asymmetry which is at odds with the objective of the CACM code.

We also consider that Option 1 may result in greater forward market liquidity as independent generators can trade without the uncertainty of the scheduling risk, with opportunities to improve their margins should they be able to execute a more efficient trade in the shorter term markets as the intermittent generation volumes become firmer. Hence while Options 1 and 3 may not be too dissimilar when market power and market making obligations are factored in, we consider Option 1 provides more scope for efficiency in the critical forward market from which most customer prices are determined.

In relation to adaptability, Option 1 is the closest HLD option to the Target Model and the markets operating in the NWE region and hence there is likely to be less risk of a requirement for further transformational change. Option 2 effectively operates both a Bilateral and Pool market and hence is both inefficient in terms of resources for participants and does not appear a workable solution and may be difficult to change. We have major reservations in relation to Option 3 in respect of its mandated reliance on Euphemia to produce a feasible schedule (as outlined in the Baringa report⁷). There is a risk that limits could be imposed (as is the case in other trading exchanges) to

⁷ Baringa Report titled "I-SEM HLD Consultation: Background paper on HLD option 3"

ensure a solution is found within the required timeframe but which may result in a less efficient solution and that creates risks for generators. It could also result in inefficient trading which would lead to the need for further market change.

Option 3 also relies on the Euphemia algorithm to provide the local wholesale market but the governance of the coupling arrangements may take limited cognisance of the peripheral market in Ireland and therefore there will inevitably be some ceding of control to bodies with no accountability to consumers or market participants in Ireland.

We believe Option 4 will not deliver efficient cross-border trading due to the risks arising from trades in the DAM and IDM being financial with ever increasing uncertainty over scheduling as wind penetration increases. This is likely to lead to the need for further adaptation and cost.

Option 1: Adapted Decentralised Market

7. Are there any changes you would suggest to make the Adapted Decentralised Market more effective for the I-SEM (for instance, a different choice for one or more of the topics or a different topic altogether)?

As has already been identified above, PPB considers this market model is the simplest and most rational market design from a purest view but the primary issue relates to how market power is mitigated across each of the relevant timeframes from the forward market through to the balancing market. A benefit of adopting this simpler, more flexible market structure and addressing market power separately is that it would allow for adjustment of the mitigation measures as the market evolves to ensure the market is delivering efficient outcomes for customers (this could be to increase or decrease the measures).

There may also need to be a reconsideration of the timing after which bids to the TSOs become mandatory as the current proposal for this to occur at the IDM gate closure may be too late to facilitate effective and efficient balancing and dispatch. It is also not clear why generators with priority dispatch are exempt from participating since the TSOs may need to redispatch generating units for balancing or constraint management which will presumably use the same bids and therefore the TSOs will need to know the potential costs of all actions it might take so that it can minimise the cost of any actions they are required to take to balance and operate the system securely. This may mean the bids may need to be expanded (e.g. to include start/stop costs).

8. Do you agree with the qualitative assessment of the Adapted Decentralised Market against the HLD criteria? If not, what changes to the assessment would you suggest (including the relative strengths and weaknesses of an option)?

PPB does not have any strong objections to the qualitative assessment although we consider the efficiency and practicality measures are stronger than has been assessed by the RAs (again assuming that the market power and market making measures are appropriately implemented, although this is a significant issue for each of the HLD options). In addition, PPB disagrees with the assessment that the option could be a strength or weakness in relation to compliance with the IEM. As the design most closely mirrors the Target Model, it should be the highest assessment, yet is assessed as lower than Option 3 which cannot be correct.

9. How does the Adapted Decentralised Market measure against the SEM Committee's primary duty to protect the long and short term interests of consumers on the island of Ireland?

PPB believes that assuming appropriate Market Power mitigation and Market Making measures are put in place, this market will result in the most efficient market coupling as it will ensure equality of treatment in the coupling processes by enabling generators on both sides of interconnectors to compete on a common basis that is voluntary and within the context of having been able to conclude some degree of self-scheduling prior to the DAM coupling. The closer alignment of the arrangements with the energy market design in GB may also

may also increase competition and avoid being “different” to the other NWE market designs which could reduce the risk of further change to increase alignment at a later date. This market design will also be familiar to investors which may facilitate investment.

Option 2: Mandatory Ex-Post Pool for NET Volumes

10. Are there any changes you would suggest to make the Mandatory Ex-post Pool for Net Volumes more effective for the I-SEM (for instance, a different choice for one or more of the topics or a different topic altogether)?

PPB considers this option captures the worst of all worlds by creating both Bilateral and Pool markets in what is a naturally small market. Such a market is untried and is likely to be the most expensive for participants.

11. Do you agree with the qualitative assessment of Mandatory Ex-post Pool for Net Volumes against the HLD criteria? If not, what changes to the assessment would you suggest (including the relative strengths and weaknesses of an option)?

PPB largely agrees with the qualitative assessment of this HLD option although we consider the efficiency and practicality measures may be weaker than has been assessed by the RAs. There are likely to be significant risks of price discontinuities between the Forward, DAM and IDM markets and the prices derived in the NET Pool for the residual balance. We also consider that this model is less adaptive and there is a high risk the design would require significant change and to keep aligned with further evolution of the Target Model.

12. How does the Mandatory Ex-post Pool for Net Volumes measure against the SEM Committee’s primary duty to protect the long and short term interests of consumers on the island of Ireland?

It is not clear that there will be efficient like for like market coupling as it may be the case, dependent on pricing, that intermittent generation decides to delay participation until the NET Pool stage. This could result in inefficient market coupling and give rise to energy flows that should not occur. The extent of this risk will depend on the relative prices in the different markets, and on the wind forecasting risks that wind generators would be taking on by competing in the DAM and IDM, relative to the greater certainty they achieve from participation in the ex-post pool.

Option 3: Mandatory Centralised Market

13. Are there any changes you would suggest to make the Mandatory Centralised Market more effective for the I-SEM (for instance, a different choice for one or more of the topics or a different topic altogether)?

There is a significant risk with this option due to the fact the market is wholly reliant on Euphemia producing coherent results which as we have previously outlined is not assured. It is likely all generators will seek to employ sophisticated bid structures with multiple conditions to seek to mirror their underlying Commercial and Technical capabilities. From our experience of despatch algorithms, this layer of complexity will undoubtedly either extend the solution time to reach the minimum cost solution or have to compromise on the solution to enable the algorithm to conclude within the imposed time constraint (see the Baringa paper⁸ for further detail). We have major concerns that this creates a significant risk to the viability of this option and therefore, notwithstanding our preference for Option 1 with appropriate market making and market power mitigation measures, we would suggest that the mandatory nature of the DAM would need to be relaxed to provide the opportunity for certain generators (e.g. independent generators with capacity under a threshold of say 1000MW) to trade bilaterally in the forward markets and with options on whether to trade in either the DAM or IDM markets.

We also have a concern that the proposition is for trading to be “Exclusive” in the IDM. This trading platform is as yet undefined and there is high risk of committing to such a platform without understanding whether it will meet the requirements of the I-SEM. We would therefore suggest that it would be better to allow flexibility for participants (again this could be limited to non-dominant generators/suppliers) to trade bilaterally within day to manage their supply and demand risks.

The proposal demands mandatory participation for conventional generation but is less clear for wind generation and demand, where in paragraphs 8.3.4 and 8.3.5 participation is described as mandatory but on a “best endeavours” basis, while in Figure 12, demand participation is shown as voluntary. There is a risk that if there are skewed obligations with conventional generators mandated, that they could be exposed to distorted prices. Given day ahead uncertainty, wind generators may be incentivised to understate their output expectations and similarly it may always be advantageous for Suppliers to understate demand which would tend to reduce the clearing price. This could also have implications for the efficiency of coupling since trading in the I-SEM would be mandated whereas the GB traders would be able to select how they participate which may enable them to cherry pick to their advantage.

⁸ Baringa Report titled “I-SEM HLD Consultation: Background paper on HLD Option 3”

14. Do you agree with the qualitative assessment of Mandatory Centralised Market against the HLD criteria? If not, what changes to the assessment would you suggest (including the relative strengths and weaknesses of an option)?

PPB disagrees with a few of the assessments made in relation to this HLD option. In terms of practicality, the option is wholly reliant on the Euphemia algorithm, the functionality of which is beyond the control of the SEMC and which is complex and difficult to understand and model and will be opaque to customers (and investors).

Equity is assessed as a potential strength but this ignores a number of critical weaknesses.

The design matches mandatory participation in Ireland with optional participation by participants on the other side of interconnectors which could be disadvantageous to, and discriminate against, participants in the I-SEM.

The design, subject to clarification on what “best endeavours” means for wind, also mandates wind to take on risk by forecasting its output even though in that timeframe it is inherently unpredictable. This could have a much greater impact on smaller wind generators who may not have the resources available to improve its forecasting capability to the same extent as larger wind generators with greater availability of resources.

The design also forces all participants to trade through the DAM which clears in Euros. This will impose a currency cost on Northern Ireland participants because it is mandatory to participate and this will ultimately result in an additional cost for NI consumers. Where participation is voluntary, the generator or supplier can choose whether to participate and bear that cost. This also has implications for the functioning of the forward market for NI participants.

In relation to Competition, while the design concentrates volumes in the DAM, it is not clear that this will result in an overall benefit for customers. It generates new risks and risk usually results in higher prices. In addition, liquidity and competition in the forward market may be lower under this option than could be the case under Option 1.

In relation to the Environment, it is not apparent why Option 3 is assessed to be stronger than Option 1, particularly as Option 3 requires some level of commitment by renewable generators to an output level when its actual production remains uncertain.

Finally, as we note in our response to Question 8, we do not agree that Option 3 is more IEM compliant than Option 1, particularly given some of the concerns described above.

15. How does the Mandatory Centralised Market measure against the SEM Committee’s primary duty to protect the long and short term interests of consumers on the island of Ireland?

As noted in our responses to Questions 13 and 14, there is a great deal of uncertainty and risk attaching to mandated reliance on both the Euphemia algorithm for the DAM and on the as yet to be developed Shared Order Book

arrangements for the IDM. This mandated participation also creates risks when coupling to the GB market which do not mandate participation in either of those markets and it is unclear what dynamic this will produce. The market also imposes risks on wind generators through enforced participation that could ultimately impact on customers and similarly, the forced participation through the EU trading platforms will create currency exposure for Northern Ireland participants that will again likely result in additional costs for customers.

Option 4: Gross pool – NET Settlement Market

16. Are there any changes you would suggest to make the Gross Pool – Net Settlement Market more effective for the all I-SEM (for instance, a different choice for one or more of the topics or a different topic altogether)?

PPB has significant concerns in relation to Option 4 and in particular whether it is really compliant with the Target Model requirements. The proposition that all DAM and IDM trades will be financial for I-SEM participants is likely to discriminate against generators in the SEM relative to all counter-parties in the market coupling and shared order book processes who will become party to a firm physical trade. The financial trades are also likely to be much less risky for suppliers in the I-SEM who, while they have some demand volatility, will have a high level of confidence in their demand levels and hence that any financial contract will be an effective hedge.

This is not the case for generators who may not be scheduled in the ex-post Gross Pool and who may therefore be adding to risks and indeed could be deemed to be participating in hedging for other than own use purposes which risks different accounting obligations. This will be a particular problem for non-portfolio generators, wind generators and generators who are at the margin and whose place in the schedule is largely dependent on the levels of output from wind generators, and this problem will expand as wind penetration increases. These risks may mean only baseload or portfolio generators will participate in the DAM and IDM markets and this is unlikely to result in efficient cross-border trading which is at odds with the objective of the IEM.

It is also unclear whether there is scope for bids into the DAM and IDM markets getting out of sync with the bids into the Gross Pool and whether this creates an exposure for I-SEM generators.

These risks will similarly result in less liquidity in the Forward market and again this will make it more difficult for Suppliers to manage price risks in accordance with the desires of most customers who want fixed prices.

17. Do you agree with the qualitative assessment of Gross Pool – Net Settlement Market against the HLD criteria? If not, what changes to the assessment would you suggest (including the relative strengths and weaknesses of an option)?

PPB disagrees with a number of the assessments made in relation to this HLD option. There are significant changes required and there must be a high risk of further change being required and hence we would not agree that this is

necessarily the most stable option. In relation to efficiency, as we noted above, we believe this option creates risks for mid-merit and marginal generators which may result in their effective exclusion from the DAM and IDM markets which is likely to mean cross-border trading will not deliver efficient flows and that the forward market will be illiquid. The consultation also notes there is a risk that the financial contracts may be subject to financial regulation which would impose different obligations and costs on I-SEM participants.

Similarly in relation to equity, the design is more favourable to parties on the other side of the interconnectors and to some extent Suppliers in the I-SEM and hence discriminates against indigenous generators who may be taking on additional risk by participating in the ex-ante markets.

In relation to Competition, the design does focus competition into the ex-post Pool but may actually reduce competition in the earlier market timeframes which are the more relevant markets for customer pricing.

Finally we agree that it may be harder to change this market in response to the likely evolution of the IEM and we believe this option risks failing to deliver the Target Model and hence is at high risk of further change within a short time.

18. How does the Gross Pool – Net Settlement Market measure against the SEM Committee’s primary duty to protect the long and short term interests of consumers on the island of Ireland?

This option takes the smallest step towards alignment with the wholesale trading arrangements operating in North West Europe and hence it is likely to be the most exposed in relation to having to undergo further redesign to meet the EU’s objective of a fully integrated electricity market. The option risks failing to capture the benefits of market coupling and could actually result in encouraging inefficient trades, which may provide the optics of market coupling but which would not be in the interests of consumers.

Capacity Remuneration Mechanisms

19. What are the rationales for and against the continuation of some form of CRM as part of the revised trading arrangements for the I-SEM?

While energy only markets could theoretically remunerate capacity, it requires a fully efficient and competitive market. It also requires that prices can spike to the Value of Lost Load (VOLL) in a number of hours in a year to provide remuneration for capacity. However, there are often price caps in markets (as there is in the SEM (€1000/MWh) and as we understand exists in the Euphemia market coupling algorithm (€3000/MWh), both of which are significantly lower than the VOLL determined by the SEMC (€10,898/MWh). This means there is “missing money” and therefore capacity will not be remunerated.

A further problem with reliance on an energy only market is that prices need to spike but this can be very volatile and may occur less than average in one year and more than average in other years. The growth in intermittent capacity further increases this volatility since there needs to be a coincidence of high demand, low wind and plant unavailability to create scarcity. This represents a significant risk to investment and this volatility will increase the cost of capital for investing in such a market.

As we described in our response to Question 2 above, there are also significant small market factors and regulatory/political risk factors that magnify the risk such that a reasonable remuneration of investments will be virtually impossible in the I-SEM and therefore a CRM is essential in the I-SEM to ensure generators can earn a reasonable return of their investment and provide the investments required to ensure the long term security of supply for consumers.

Further analysis of the continuing need for a CRM is set out in Section 3 of the NERA report⁹ that was produced for Viridian Group and which presents NERA’s assessment of the case for a CRM in Ireland.

20. Are these the most important topics for describing the high level design of any future CRM for the I-SEM?

The topics identified in Table 9 seem to cover the most important topics. However the descriptions of the various options are not fully developed and therefore the more feasible options will require more detailed definition to enable a full assessment before any final selection.

⁹ NERA Report titled “The Capacity Remuneration Mechanism in the SEM”

Option 1: Strategic Reserve

21. Are there any changes you would suggest to make the design of a Strategic Reserve mechanism more effective for the I-SEM (for instance a different choice for one or more of the topic?)

PPB does not consider a targeted CRM is appropriate for the I-SEM as it will distort the energy market and will inevitably become the sole route by which capacity is commissioned (i.e. the slippery slope). It does not actually address the issues identified that drive the requirement for a CRM and therefore will not address the fundamental objective of ensuring the appropriate remuneration of generating capacity to ensure security of supply for customers.

22. Do you agree with the initial assessment of the strengths and weaknesses of a Strategic Reserve Mechanism? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?

As we noted in the response to the previous question, we consider that a strategic reserve mechanism will interfere with the energy market and therefore is not capable of being fully ring-fenced as the paper suggests.

23. Would a Strategic Reserve Mechanism work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?

As we have already noted, we don't believe a Strategic Reserve Mechanism meets the objective of a CRM and therefore will be equally ineffective with each of the energy trading arrangements.

Option 2A: Long-Term Price Based CRM

24. Are there any changes you would suggest to make the design of a Long-term price-based CRM effective for the I-SEM (for instance a different choice for one or more of the topic?)

PPB considers a long-term price based CRM is the most appropriate CRM for the I-SEM and from the perspective of regulatory certainty, there would be significant benefits from the retention of an arrangement closely aligned to the current CPM.

A key issue with the high level proposition in the consultation paper is the proposal to have the same capacity rate for generation and demand, notwithstanding the system will require a generation margin to provide reasonable security of supply to customers. This feature appears to be designed to enable cross-border access to the CRM but if there is no equivalent inclusion in GB (which considering GB's proposed CRM design will not) such inclusion will distort the coupling of the energy market and result in inefficient trades. We therefore consider that unless the GB proposals change, Interconnector flows should not participate in the CRM mechanism.

25. Do you agree with the initial assessment of the strengths and weaknesses of a Long-term price-based CRM? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?

PPB agrees that a long-term price based CRM will provide greater year-on-year stability for both generators and consumers and will best promote security of supply. However it is difficult to make a detailed assessment until a more detailed design of the CRM and its operation is specified.

26. Would a Long-term price-based CRM work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?

PPB considers a long-term price based CRM could work equally effectively with any of the energy trading arrangements

Option 2B: Short-Term Price Based CRM

27. Are there any changes you would suggest to make the design of a Short-term price-based CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?

PPB considers a short-term price based CRM will not address the primary objective of a CRM which is to provide price stability and to remove regulatory/political risk that would exist in an energy only market. The ex-post nature of this form of CRM will inevitably result in volatile prices for both generators and consumers and therefore will not provide the stable revenue streams to incentivise the appropriate investment required to provide security of supply.

28. Do you agree with the initial assessment of the strengths and weaknesses of a Short-term price-based CRM? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?

PPB agrees that a short-term price based CRM will inevitably provide volatile revenues and therefore doesn't provide the stability desired.

PPB does not agree that it provides any material incentive for generation to be available at times of scarcity as there are very few generator outages that are discretionary. Unplanned outages do occur and in such circumstances generators will seek to return the generating unit to service as quickly as possible. There is some discretion in relation to planned outages but again that flexibility is generally utilised where notice is available. However, once a planned outage has commenced, they is little scope to respond to a scarcity signal.

PPB agrees that there is a significant risk of gaming under this CRM option and this is a particular risk in the I-SEM given the existence of dominance in the market.

29. Would a Short-term price-based CRM work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?

PPB considers that a short-term price based CRM would be equally ineffective with each of the energy trading arrangements.

Option 3: Quantity Based Capacity Auction

30. Are there any changes you would suggest to make the design of a Quantity-based Capacity Auction CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?

It is difficult to properly assess the design in the absence of greater detail. However a particular concern is that the value of capacity in the auctions could be volatile for the same reasons scarcity rents in an energy only market would be volatile, e.g. the relative size of an efficient new entrant CCGT (c400MW) could depress prices for 4 to 5 years.

There is also a significant risk from market power that would require significant market power mitigation measures, not just in the initial auctions but also in the secondary market that would be required to enable generators to manage their contracted position. The penalty arrangements are also a critical element of the design and they could play a significant role in determining whether generators participate in the auctions.

In relation to cross border trading, we note that the current GB proposals exclude interconnectors from the proposed CRM and it would seem incompatible to seek to include interconnectors in the I-SEM when they are excluded in GB.

31. Do you agree with the initial assessment of the strengths and weaknesses of a Quantity-based Capacity Auction CRM? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?

PPB does not agree that a Capacity Auction will inherently provide a “relatively stable environment for capacity investment”. The effect of new entry in a small system will make it volatile and the threat of gaming from a dominant portfolio generator will mean significant market power mitigation measures would need to be imposed on both the primary and secondary markets. This in turn introduces regulatory risks that cannot be quantified without understanding the design of the mitigation measures and how they would operate and also the process for change.

32. Would a Quantity-based Capacity Auction CRM work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?

PPB considers that a quantity based capacity auction CRM is likely to be equally ineffective with each of the energy trading arrangements.

Option 4: Quantity Based Capacity Obligation

33. Are there any changes you would suggest to make the design of a Quantity-based Capacity Obligation CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?

PPB considers that this model suffers from the same problems as the centralised Capacity Auction CRM (see question 30 above). The design could also confer significant benefit to market participants who are vertically integrated unless there is an explicit requirement to auction all certificates. However, it may be difficult to establish a liquid market that would allow suppliers equality of access to capacity to meet their capacity obligations and to trade these permits as suppliers' retail market shares change. This could have a detrimental effect on retail competition and therefore consumers.

34. Do you agree with the initial assessment of the strengths and weaknesses of a Quantity-based Capacity Obligation CRM? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?

PPB does not agree that a capacity obligation CRM will reduce the regulatory involvement as there are significant market power measures and this would extend under this option to both the generation and retail market participants. We also agree that the market could be onerous for new and/or small suppliers and could establish a barrier to entry.

35. Would a Quantity-based Capacity Obligation CRM work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?

PPB considers that a quantity based capacity obligation CRM is likely to be equally ineffective with each of the energy trading arrangements.

Option 5A: Centralised Reliability Options

36. Are there any changes you would suggest to make the design of a Centralised Reliability Option CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?

It is difficult to comment of the Centralised Reliability Option CRM design as there is little information in the consultation paper. The options appear to be a one way CfD against energy prices. However it is not clear how the “option” value would be determined as it would need to take account of the prices that would occur in the energy market, what caps would be imposed and what regulatory risks could impinge on the prices in the energy market.

If the CfDs are to be auctioned (e.g. based on the lowest option fee required to enter the CfD) then the same issues in relation to market power exist as we highlighted in response to Question 30 above. In addition, generators who are not in the energy market to which the CFD strike price is referenced could have significant price exposure (i.e. no revenues but a liability under the CfD).

37. Do you agree with the initial assessment of the strengths and weaknesses of a Centralised Reliability Option? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?

The scope for revenue volatility, the risks from market power and the exposure to CfD payments at times when the generator is not receiving the market price makes this option particularly unattractive and we doubt any revenue streams from this CRM would be bankable with potential investors.

Small markets add a further level of complexity due to fewer participants and with concerns relating to market dominance and it would therefore seem to be a significant risk to adopt such a mechanism in a small market, particularly as reliability options seem to have been contemplated in the early stages or the EMR process in GB and swiftly discounted.

38. Would a Centralised Reliability Option work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?

PPB considers that a Centralised Reliability Option CRM is likely to be ineffective with each of the energy trading arrangements although this would be particularly so in energy arrangements that do not have one of the market timeframes within which trading is concentrated and against which the strike price could be referenced.

Option 5B: Decentralised Reliability Options

39. Are there any changes you would suggest to make the design of a Decentralised Reliability Option CRM effective for the I-SEM (for instance a different choice for one or more of the topic)?

PPB considers this option suffers from the same problems as the Centralised Reliability Option CRM (see our response to Question 36 above). In addition, the decentralised version adds retail market dominance as a concern to be addressed and similar to the Capacity Obligation CRM, creates extra burdens on suppliers and requires a liquid market in Reliability Options to enable participants to manage their exposures and to refine their holding as they gain or lose market share. This will in turn require more sophisticated trading arrangements and additional credit collateral requirements. The combined effect may be a barrier to entry for suppliers which would be detrimental to retail competition.

40. Do you agree with the initial assessment of the strengths and weaknesses of a Decentralised Reliability Option? If not, what changes to the assessment would you suggest (including the strengths and weaknesses of an option relative to the others)?

PPB considers that it is difficult to assess the option without a full definition of the proposition. However, at a generic level we consider that it is likely to be complex to operate, creates additional risks for Suppliers, is likely to suffer from revenue volatility, is at high risk from market power and could create significant exposure to CfD payments at times when a generator is not receiving the market price. These again make this option particularly unattractive and we doubt any revenue streams from this CRM would be bankable with potential investors.

This model does not appear to be functioning in any other market and the small market size adds a further level of complexity due to fewer participants and market dominance. It would therefore seem to be a significant risk to adopt an untried mechanism in a small market, particularly as reliability options seem to have been contemplated in the early stages of the EMR process in GB and swiftly discounted.

41. Would a Decentralised Reliability Option work or fit more effectively with a particular option for the energy trading arrangements. If so, which one and why?

PPB considers that a Decentralised Reliability Option CRM is likely to be ineffective with each of the energy trading arrangements although this would be particularly so in energy arrangements that do not have one of the market timeframes within which trading is concentrated and against which the strike price could be referenced.