SEM-14-045

Integrated Single Electricity Market

SSE response to Draft Decision Paper on High Level Design for Ireland and Northern Ireland

July 2014

Table of Contents

Introduction and Executive Summary

About SSE

Thank you for giving SSE the opportunity to comment on the SEM Committee's consultation paper on Integrated Single Electricity Market Arrangements for 2016. This consultation paper represents an important step in the design of enduring trading arrangements for the island of Ireland.

SSE is a utility with both generation and supply interests in Ireland and Great Britain (GB). We own and operate over 500MW of wind generation capacity in the Single Electricity Market and over 1000MW of thermal generation capacity, with a new 461MW CCGT being commissioned later this year. SSE also owns over 11,000MW of generation capacity in GB. Across these core markets, we supply more than 9 million customers with energy.

To secure energy for its retail customers, SSE is involved in electricity generation, gas production, energy portfolio management and gas storage. Amongst other things, the company is the leading generator of electricity from renewable sources across the UK and Ireland. Its wholesale business priorities are competitiveness, sustainability and flexibility.

Our concerns and solutions

Energy Trading Arrangements

SSE is broadly happy with the structure of the Energy Trading Arrangements. However, we have identified a couple of functional issues that will require immediate resolution and a couple of follow on changes that will require work/thought during the detailed design phase. Some of these changes might be classified as 'detailed' design, but we feel that they are absolutely fundamental to the proper functioning of the market as proposed.

SSE notes that the RAs appear to have taken 'detailed' design decisions already, including the choice of a single versus a dual pricing regime. There is precedent to include the first of these modifications in the HLD:

- Financial forward contract liquidity will need to improve under any market design. The forward stage will require regulatory intervention defined in the High Level Design to provide opportunities for smaller suppliers to compete in the market. **A Forward Market Making Obligation on vertically integrated participants (including SSE) and a centralised platform for forward trades with an independent clearing house can deliver financial forward market liquidity. This is a HLD issue and must be addressed in the final decision released in September. Physical Forwards are effectively allowed under the Proposed HLD, as explained in Annex B.**

- There is very little effective difference between PTRs and FTRs. PTRs should not reduce the amount of physical cross-zonal capacity available for implicit allocation, and with firm prices at the DA and ID stages, they will be used more efficiently by participants than they are now. If they are not, other participants will find it much easier to reverse the error through arbitrage. **If there is an issue with the use of PTRs, the RAs can act to address the actual market failure e.g. by introduction of FTRs.**

- **Perverse incentives under out of market support schemes need to be examined as part of detailed design.** While market support schemes are out of the scope of the market design, the incentives they create for participants need to be fully understood before the HLD is finalised.

- Variable generators are taking on a substantial commercial risk in I-SEM. We are assuming that they will have a firm physical/commercial position, and will not be considered a 'price taker' in the balancing arrangements. **Variable generators will therefore be able to bid in INC or DEC bids that reflect the true value of changes to that physical position[1].** By managing these commercial risks, the incentives to deliver an energy dispatch and ultimately system that provides adequate physical access[2] will shift to the TSO.

- Market concentration exists for flexible plant, particularly with regard to storage and hydro. Given the benefits for flexibility proposed under the balancing market, concentration needs to be examined. The proposed decision paper outlines **proxies for structural reform** including a Virtual Power Plant (VPP) auction. **Given market concentration, SSE suggests that a VPP auction would have best effect in this market segment:**

    - It would reduce financial incentives on dominant participants to exercise market power.
    - It would allow smaller suppliers and generators to mitigate the volatility, complexity and risk of the imbalance pricing regime (as eventually defined).

- The price reference for imbalance pricing is defined as the most expensive untagged 1MWh. **Given market power concerns and the likely quantum of overall system balancing error, SSE believes that the RAs should examine a Price Average Reference[3] (PAR) higher than 1MWh for calculation of imbalance prices.** Marginal pricing in the balancing market could be retained through a fund that collects the residual cash requirement across all demand, blunting exposure and limiting incentives to exercise market power.

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[1] This will include the value of support mechanisms that pay out on metered output, i.e. Renewable Obligation Certificates, REFIT Floor Price and CfD FiTs.
[2] This should cover both curtailment and constraint.
[3] The calculation of the imbalance price would be based on an average of the most expensive offers accepted in the imbalance mechanism, rather than the most expensive offer.

Capacity Arrangements

SSE is less confident that the proposed Capacity Arrangements can deliver for Irish consumers. While we agree that **Centralised Reliability Options** are preferable to a Capacity Auction (or decentralised options, like Capacity Obligations etc), we think that the RAs need to be very careful with the detailed design criteria:

- In an auction for Centralised Reliability Options, you are effectively pricing a derivative. **The value of the derivative will reflect its contractual cash flows in possible future states of the world.** The probabilities of various possible future states of the world will always be limited if you are auctioning an annual product, therefore the value released at each auction will be volatile as the system moves between surplus and deficit. **While competitive price discovery is partially beneficial for customers, any CRM is likely to require regulatory intervention to 'bound' price responsiveness. This would take the form of a price collar/floor or a price stability mechanism.**

- Participants with sufficient portfolio scale will have incentives to game the interactions Reliability Options have with their reference market (along with the auction itself). Capacity that is not covered by a Reliability Option will not be capped in the reference market. **A portfolio generator with market power will be incentivised to push the price above the strike price for the Reliability Option to both outperform its fixed costs during periods of system scarcity and trigger liabilities for competitors who have also sold Reliability Options.** This incentive to trigger excessive system price events is a substantial risk in concentrated wholesale markets and unique to Reliability Options. **The RAs need to be aware of this during detailed design.**

- Pure Reliability Options do not even attempt to solve the missing money problem, because they mean that the auction described is trying to value **expected scarcity** rather than the **physical capacity** required to deliver a desired reliability standard. **Pure reliability options with limited pre-qualification and non penalties for physical non-delivery will not deliver a desired reliability standard.** They will simply financially hedge suppliers up to the Day Ahead price cap, and provide a limited revenue stream for participants willing to provide the associated insurance product. **This is a HLD issue and must be addressed in the final decision released in September. If the RAs want to deliver a required reliability standard (i.e. LOLE of 3 hours per year) they will need to specify explicit physical backing for issuers of Reliability Options.**

- Any movement away from a **Day Ahead Reference Price** is effectively confusing multiple products and revenue streams – by using an Intraday or Balancing Market reference price:

  - You place additional non-energy risks on physical issuers which will be reflected in the clearing price in the auction.
  - You place an unnecessary constraint on delivery of the physical capacity required to meet the desired reliability standard.

- You increase price volatility in the annual auction by involving uncertain, subjective costs beyond delivery of physical capacity.

Ultimately, customers will be paying to oversupply flexible capacity, because the balancing market and system services revenue streams are already designed to fully compensate those products. **By oversupplying flexible capacity, you will distort short-term price signals in the Balancing Market and misprice the DS3 system services auctions.** **This is not a desirable outcome – the RAs should not expand the focus of a Capacity Mechanism beyond pure resource adequacy.**

If further information or clarification is required on any aspect of this response, SSE will be delighted to provide the RAs with the required information. We also look forward to working with the RAs Project Office on the detailed design arrangements.

The project plan states that this work will take place between September 2014 and February 2015, with delivery of a detailed design in February 2015. Given the range of issues that need to be covered, we think that this is unrealistic. There are elements of design that need to be finalised for implementation and elements of design that can be finalised later.

The RAs should fully utilise the expertise that market participants have in the detailed design phase by setting up technical working groups on individual design elements. For elements that will clearly require further work (i.e. Forward Liquidity) these can be set up in advance of the publication of the Final Decision.

Assessing the Proposed HLD

Different components and different criteria

The "Initial Impact Assessment[4]" divides the assessment criteria into primary assessment criteria and secondary assessment criteria. The paper states that:

"When making a trade-off between competing objectives in relation to the decision on the I-SEM HLD, the primary assessment criteria take precedence over the secondary assessment criteria."

In responding to this consultation, we have carried out the same exercise, assessing each of the **components** of the proposed arrangements against **primary** criteria. We have then assessed the proposed arrangements against **secondary** criteria to identify other issues. Our primary criteria align with those criteria chosen by the SEM Committee, with the competition criteria effectively becoming **control of dominance.**

The capacity mechanism is not integrated into the energy trading arrangements. However, incentives in the **proposed CRM** flow into **proposed ETA** and vice versa. Therefore, our analysis is of the arrangements as a whole. The assessment criteria are detailed below with a brief assessment:

Primary Assessment Criteria

Internal Energy Market (IEM)

"[T]he market design should efficiently implement the EU Target Model and ensure efficient cross border trade."[5]

The model chosen clearly implements the EU target model and should move SEM from a position of cross border arbitrage to genuine market coupling.

Security of Supply

"[T]he chosen wholesale market design should facilitate the operation of the system that meets relevant security standards."[6]

The TSOs should have sufficient information on and control over the plant on the system under the arrangements chosen. However, the TSO may not necessarily have sufficient plant on the system to meet expected demand. **Reliability Options will need careful design in order to provide a stable signal for capacity.**

[4] SEM-14-046 Next Steps Decision Paper (2013), SEM Committee
[5] Underpinned by EU Electricity Regulation 714/2009, European Electricity Network Codes
[6] Underpinned by EU Directive 2005/89/EC

Competition

"[T]he trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner"[7]

The existing market power measures have been dismantled under the proposed energy trading and capacity arrangements. **This will require regulatory intervention to compensate, European liquidity isn't sufficient protection across all time periods:**

- A market making obligation on vertically integrated participants in the forward time period would allow suppliers access to risk hedging products.
- A VPP auction of flexible capacity would limit the exposure of participants to market power in the balancing and imbalance periods.

Control of dominance is a priority area, and must be central to detailed design.

Environmental

"[W]hile a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables."[8]

We see two issues for renewable generation – firstly, exposure to market power in the balancing and imbalance periods and secondly, incentives to participate under REFIT. **Government targets for renewables will only be facilitated if market reference prices are achievable by the average wind generator.** CfD FiTs and the Renewable Obligation already expose generators in Northern Ireland to normal market incentives.

Equity

"[T]he market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner.[9]"

Regulatory intervention will be required to ensure sufficient access to forward markets. Penal (cost reflective) pricing appears to be the guiding principle behind balancing market design; however this necessarily makes participation more difficult for smaller generators and suppliers. **A balance between market access and cost reflectivity needs to be struck[10].**

[7] Underpinned by SEMC Primary Objective, Objective on transparent pricing and EU Electricity Regulation 714/2009
[8] Underpinned by SEMC Objective on the environment and promotion of RES and EU Directive 2009/28/EC
[9] Underpinned by SEMC Objective to avoid unfair discrimination
[10] Very penal prices will favour larger participants. Very soft pricing won't provide the right pricing signals for investment and operation of generation assets.

Secondary Assessment Criteria

Adaptive

"The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner."

Governance arrangements are a detailed design issue, but the Trading and Settlement Code (TSC) and the Modifications Committee have provided a level of transparency, process and rigour to market development. **These characteristics should be retained under the detailed governance arrangements in any new market design.**

Stability

"[T]he trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations."

The energy trading arrangements are heavily dependent on shared order book functions. This will limit scope for regulatory interventions in the DA and ID periods. However, the design of local arrangements (Forwards and Balancing) will also dictate participant exposure to the shared order book. **We would note that the chosen capacity market design will likely require regulatory interventions if it is to achieve a stable price signal to support security of supply.**

Efficiency

"[M]arket design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant."

The model chosen should move SEM from a position of cross border arbitrage to genuine market coupling. **Interconnector flows will be more efficient than under SEM, resulting in a more economic dispatch of available plant[11].**

However, incentives to guess system length under the proposed balancing arrangements will be strong. This may result in gaming.

Practicality

"[T]he cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced."

The Impact Assessment is neutral on central and participant costs[12]. **SSE suggests that it is difficult to assess this criterion across different options.** However, we would favour

[11] However, dispatch will reflect scarcity pricing from generators without an RO contract. The definition of 'least cost' changes under I-SEM.
[12] Except under Option 2, this option is assumed to have higher central costs.

implementation from an experienced project delivery body to ensure that costs are kept as low as practical[13].

Forward Market

Internal Trades

"[T]he SEM Committee proposes that all forward contracts will be financial in nature, i.e. Contracts for Differences (CfDs)."

Are there sufficient incentives for suppliers and generators to contract forward?

Suppliers are entering into fixed forward contracts with end customers for the supply of energy, therefore there are strong incentives on suppliers to contract forward, assuming that forward prices are competitive i.e. reflective of near-term reference markets.

Generators are to a lesser extent entering into some physical forward contracts with fuel suppliers[14]. The strength of their incentive to trade forward is based on the link between selling forward and physical production. The ability of **generators** to meet their forward commitments will depend on the degree of certainty around their own market volumes and the extent to which running costs can be captured in the structure of offers.

Liquidity and transparency in near term markets should help futures markets develop. However, while the proposed design will provide a standardised spot contract on which longer-term contracts can be written[15], it does not provide any additional incentives for **generators** to contract forward.

Both design and concentration limit forward market liquidity

As we noted in our response to the initial High Level Design consultation, the CER-ESB Asset Strategy[16] did not lead to any significant changes in the underlying ownership structure in the Ireland. If there are limited incentives for generators to contract forward, participants with sufficient market power can extract a significant premium for forward products.

The existing SEM design, along with concentration in the wholesale market provides limited incentives for dominant parties to contract forward financially or physically. This will not change substantially under the proposed design; creating a **competition** issue.

Forward contract liquidity is particularly important for new suppliers, who must enter into potentially unhedged fixed forward contracts with end customers for the supply of energy. **Financial forward contract liquidity will need to improve under any market design. The forward stage will require regulatory intervention defined in the High Level Design to provide opportunities for smaller suppliers to compete in the market.** The paper acknowledges that this may be an issue under the proposed HLD and proposes that:

[13] The delivery body does not necessarily need to be the long term operator.
[14] Fuel contracts for generation units can vary from spot to take-or-pay, and everything between.
[15] Standardised spot contracts help to concentrate liquidity.
[16] CER-ESB Detailed Agreement on Asset Strategy (2007), Commission for Energy Regulation.

"To address this, the Regulatory Authorities (RAs) will establish a workstream to investigate forward liquidity-promoting measures in the forward energy markets."

What will provide forward market liquidity?

There are a number of different solutions available to the RAs. **SSE believes that a market making obligation on vertically integrated participants would best suit Ireland.**

I. Allow for bilateral contracts for physical delivery in the forward timeframe

This would be a radical solution, as it effectively dismantles the High Level Design proposed. **SSE is opposed to this.** This is recognised within the paper, which states that:

"[T]he SEM Committee is of the view that physical forward contracting could aggravate rather than mitigate liquidity concerns by reducing the volumes of trades in the short term markets that are used to reference financial contracts, thereby making the spot market price less robust, less transparent, and less predictable. The lack of a predictable spot price would discourage market participants from referencing long term contracts against this price."

We would agree. **Allowing physical trades outside of registered market places will prevent the development of a standardised spot contract on which long-term contracts can be written[17].** A deep physical 'pool' is transparent and liquid, providing a reference for forward contracts. Given the characteristics of the Irish market, this is the most appropriate design for the SEM.

SSE has another concern that isn't explicitly mentioned in the Proposed Decision paper. Bilateral contracting outside of registered market places may lead to discrimination by generators between suppliers[18]. **Compulsion to use either the Day Ahead (DA) or Intraday (ID) markets to physically contract means that generators cannot chose to discriminate** – given Ireland's market ownership structure this is a major advantage of the chosen design.

SSE does not believe that allowing bilateral contracts for physical delivery in the forward timeframe would be a desirable solution. It would represent a substantial overhaul of the proposed design, creating issues with:

- **Competition:** reducing near-term liquidity and transparency

[17] Some respondents have suggested that mandatory counterbidding of volumes contracted forward could resolve this issue. SSE questions how effective a 'mandatory' obligation to bid against a forward contracted position would be – it would be impossible for a Market Monitoring Unit to assess how reasonable offers from generators would be. In a market that doesn't require SRMC bidding, there are no registered marketplaces for opportunity cost, VOMs or LTSAs. **Participants can easily convert financial forwards into physical forwards as explained in Annex B.**

[18] Discrimination can take many forms, from credit terms to product types. It is difficult to see how the RAs could effectively mandate against discrimination.

- **Equity:** limiting some suppliers access to forward markets

II. **Impose a forward market making obligation on vertically integrated participants – SSE's preferred option.**

As noted in SSE's initial response, the UK regulator, Ofgem, recently introduced **'Secure and Promote[19]'** licence conditions focusing on three liquidity objectives:

- **Availability of products that support hedging**
- **Robust reference prices along the curve**
- **Effective near-term market**

The effective near-term market has been solved under the proposed HLD, but the first two objectives (and solutions) would be applicable to Ireland. A regulatory intervention could impose a condition on vertically integrated participants[20] to act as market makers, providing a minimum level of liquidity[21] on an OTC platform with a narrowly limited bid offer spread.

If a market maker posts an unreasonable bid or offer, they would be required to buy or sell at the opposite price[22]. **SSE believes that this should translate into a sensible volume and price being offered for a reasonable volume of financial hedging products.** Once a market has sufficient depth, other participants would be happy to enter. **A market making obligation on vertically integrated participants would help to create a more functional and liquid forward market.**

A market maker obligation is SSE's preferred solution to forward liquidity issues. It is not a radical solution and requires no overhaul of the proposed High Level Design. It resolves the issue and creates no **competition, equity[23]** or **efficiency** issues.

Our final solution for Forward Trading is with regard to credit terms. **Ensuring that participants strike internal forward contracts on a central forward trading platform with an independent clearing house would achieve a better outcome than the current OTC arrangements**. Independent clearing rather than bilateral agreements with credit terms will limit discrimination in the forward timeframe.

[19] Ofgem (2013), Wholesale power market liquidity: statutory consultation on the 'Secure and Promote' licence condition
[20] This would include ESB, SSE, Centrica and Energia.
[21] This volume can be defined in the detailed design stage – it would be appropriate to each participant.
[22] If an expensive buy/sell of €49.5MWh/€50MWh was offered, the market maker would be obliged to buy at the unrealistic (opposite) price posted. There is an incentive to offer sensible prices.
[23] If the forward market making obligation is set at a market threshold rather than on particular licence holders, then there are no equity issues.

Cross Border Trades

"[T]he SEM Committee proposed decision is that the I-SEM High Level Design entails the auctioning of Financial Transmission Rights on the Moyle and East West interconnectors. Whether these are FTR Options or Obligations will be determined at the detailed design state as well as the auction rules."

Are the arguments for PTRs sufficiently material?

The SEM Committee states that the points raised by respondents with regard to retaining Physical Transmission Rights (PTRs) were not sufficiently strong or material enough to justify their retention. Those arguments were:

Argument dismissed by RAs	SSE view
Markets in the NWE region auction PTRs.	*Not a first order issue, although restricting PTRs does impact on the* ***adaptive*** *and* ***practicality*** *criteria.*
Traders and TSOs are more familiar with PTRs	*Not a first order issue, although restricting PTRs does impact on the* ***adaptive*** *and* ***practicality*** *criteria.*
FTRs should only be used when market coupling arrangements are established.	*This issue is resolved under the proposed market design, to the extent that the DA market coupling process works as expected.*
FTR payouts are based on day ahead market price spreads, which introduces greater risk to capacity pricing and hence revenues.	*This issue is partially resolved under the proposed market design. However, owners of FTRs will be taking on more risk. This is an* ***equity*** *issue - fewer participants may have access to cross border hedging products.*
Reduced value of interconnection (IC) capacity reduces social welfare.	*Theoretically, the value of an FTR and PTR should be equal. However, the value of a physical transmission right to a market participant is higher because it provides a participant with better risk management options. This creates an* ***equity*** *issue. The social welfare isn't reduced, but Irish customers may not be receiving a fair distribution of the social welfare benefit, given that the costs and benefits for both interconnectors sit with them.* ***This would also distort investment signals for future interconnectors too.***
PTRs with Use It Or Sell IT (UIOSI) are the	*Not a first order issue, although it does mean*

equivalent of FTR Options[24].	*that participant use of PTRs can be observed in other NWE markets.*

While familiarity should not be a major concern for the SEM Committee, concerns expressed by IC owners around the reduced value of interconnection capacity should be considered material. As the paper notes:

"In both Ireland and Northern Ireland, revenues from the sale of transmission rights on the East West and Moyle interconnectors flow through to respective end consumers by netting off against TUOS charges."

The liabilities for both of those interconnection assets also sit with end consumers, through ownership in the case of the East West Interconnector and through mutualisation in the case of the Moyle Interconnector. If these assets cannot recover their value in the market, this creates an **equity** issue for Irish customers who are not receiving a fair distribution of the social welfare benefit.

PTRs as a transitional instrument?

Given the concerns expressed by both participants and asset owners, it would seem prudent for the SEM Committee to retain PTRs as a transitional instrument.

SSE believes that there is very little difference between PTRs and FTRs. In reality, PTRs should not reduce the amount of physical cross-zonal capacity available for implicit allocation, and with firm prices at the DA and ID stages, they will be used more efficiently by participants than they are now. If they are not, other participants will find it much easier to reverse the error through arbitrage. The SEM Committee states that:

"Given the size of the I-SEM market relative to interconnection capacity, issuing PTRs would risk 'locking out' 20% of the market (i.e. the entire capacity of the cross border lines relative to the size of the all island system) from the day ahead energy market clearing process."

This is not a realistic concern, given the nature of price formation in I-SEM and the quantum of penalty/opportunity cost participants face for flowing against price. If there is an issue with the use of PTRs, the RAs can act to address the actual market failure e.g. by introduction of FTRs.

[24] Under the EU Target Model, 'Use it or sell it' (UIOSI) provisions are applied to PTRs at the DA stage. This means that if a flow has not been nominated by the DA stage, the capacity is made available for implicit allocation through the DAM (and then into the IDM if unsold in the DAM). The PTR holder receives the implicit value of the capacity in the DAM (down to a minimum value of zero)

Day Ahead Market

Day Ahead Market Participation

The SEM Committee has proposed that:

"[P]articipation in the centralised markets be exclusive, but not mandatory in any particular timeframe."

This decision acknowledges that mandatory participation might force participants to trade in a way that was counterproductive to the overall efficiency of the system and potentially discriminatory for certain technologies[25]. Given that the DA market should produce a robust commercial schedule as a basis for initial dispatch, it is important that participation is properly incentivised.

Is it structurally attractive for…

Suppliers?

The Day Ahead Market (DAM) will have a number of characteristics that make it attractive to demand:

- **Timing:** demand forecasting in advance of 18-36 hours will have a much lower error than demand forecasting further out.
- **Uniform Auction:** a uniform auction provides a robust reference price for the settlement of any financial forward contracts.
- **Access:** a Day Ahead Auction provides market access to all suppliers on equal and fair trading terms, limiting discrimination by generators.

(All) Generators?

The Day Ahead Market (DAM) will have similar characteristics that should make it attractive to generators:

- **Timing:** for a typical conventional generator, a Day Ahead auction will produce a commercial schedule with reasonable notice to re-optimise up to gate closure. For a flexible generator, market participants will move to the market in which they see the highest value. For a wind generator, forecasting 18-36 hours out will necessarily incur error.
- **Uniform Auction:** a uniform auction will mean accepted offers from most generators receive a clearing price in excess of their offer for the period. It will also provide a robust reference price for the settlement of financial contracts.

Generators supported through market interventions?

[25] Not only variable wind generation, but other flexible units that may want to realise their value in the intraday or balancing markets.

SSE has one concern with regard to the structure of the current REFIT support mechanism. REFIT 1, 2 and 3 have been successful in delivering renewable generation capacity onto the Irish system at a relatively low cost. However, this scheme effectively determines a payment due based on Actual Market Revenues[26]. Regardless of participation in I-SEM a well performing generator will receive the same as a badly performing generator:

	Generator A	Generator B
Achieved Price	€40/MWh	€65/MWh x MG
PSO Payment	€39.481/MWh	€14.481/MWh
Actual Price[27]	€79.481/MWh	€79.481/MWh

This has not been an issue in the SEM. Generators can only underperform on volume, not price. As REFIT currently stands:

- Customers carry the risk of REFIT supported generators underperforming in I-SEM.
- Day Ahead Market efficiency is reduced, because there are no incentives for REFIT supported generators to submit realistic volumes.

However, REFIT has been successful on the basis that it has reduced market price risk, and allowed projects to build on the basis of expected volumes. Any proposals to set the DA price as the reference price for renewable support schemes introduces an unrealistic element of basis risk[28]. **Discounted market reference prices that are achievable by the *average wind generator* should provide sufficient incentive without increasing the cost of capital on projects.**

Perverse incentives under out of market support schemes need to be examined as part of detailed design. While market support schemes are out of scope, the incentives they create for participants need to be fully understood before the I-SEM design is finalised. The UK equivalents, CfD FiTs and the Renewable Obligation are already designed to incentivise market participation from generators, so there is no issue in Northern Ireland.

Overall

The DA market as defined in the paper is **structurally attractive** as a result of its timing and uniform auction characteristics. **Assuming that physical capacity cannot be withheld from registered market places through bilateral physical forwarding contracting, the DA market will be sufficiently liquid without mandation.**

[26] CER (2008), Calculation of the R-factor in determining the Public Service Obligation Levy
[27] Simplified in terms of opportunity cost calculations
[28] It may be noted that the UK sets a DA reference price, however the determination of the CfD strike price properly takes account of the basis risk a wind generator faces.

The proposed decision acknowledges some of the issues around incentives to participate at the DA stage for variable generation. It also acknowledges that mandation is difficult to enforce, given that flexible plant will be offering their availability at a high opportunity cost, given the value to the system they can provide in later time periods:

*"The SEM Committee's intention behind Option 3 was that mandatory participation at the DA stage would be **on a best endeavours basis**."*

If it is decided that mandatory participation on a transitional basis from market go-live is appropriate, we would suggest that it is on the basis of **reasonable endeavours** given that **best endeavours** implies that errors or deviations from 'average' behaviour will incur market and regulatory penalties.

Day Ahead Bidding Structure

DAM Algorithm

"The specific offer structure to be employed in the I-SEM will be considered further as part of the detailed market design but at this stage the SEM Committee does not see any impediment to use of EUPHEMIA as the DAM algorithm."

Respondents to the consultation appear to have concerns about the use of EUPHEMIA to price and settle the I-SEM Day Ahead Market. EUPHEMIA as defined by the Price Coupling of Regions (PCR) project[29] is:

"[An algorithm] used to calculate energy allocation and electricity prices across Europe, maximising the overall welfare and increasing the transparency of the computation of prices and flows."

Ultimately, the MSP software in the SEM is performing a similar function – finding a commercial generation schedule (albeit for Ireland only). While testing of the EUPHEMIA algorithm would be useful for RAs, Market Participants and TSOs, we cannot see any reason why an algorithm that is producing robust commercial schedules and cross border flows across Europe would not be able to serve Ireland equally well.

Because the inputs and constraints on the algorithm are different from those applied by the MSP software, this would mean that participants would be responsible for ensuring that their commercial positions are individually physically feasible. This will be a transfer of pricing risk from the market as a whole[30] to individual generators. Given that generators know their commercial and physical constraints, they will be in a better position to manage that risk, although they may seek additional returns given the additional risk they are taking on. The MSQs currently produced in SEM bear a limited resemblance to dispatch. The TSO stated that:

"TSO intervention in the market currently amounts to approximately 30% of the total system energy demand for the period analysed here which would be typical, i.e. 30% of what we

[29] PCR PXs (2013), EUPHEMIA Public Description
[30] As this is currently a result of scheduling via a central algorithm

believe to be a normal and efficiently matched set of transactions could not be physically delivered firm due to a mixture of system services provision, constraint management and plant unavailability."

Effective management of a commercial and physical position can resolve these issues under EUPHEMIA in the same way that a complex offer structure and make whole arrangements do in SEM.

Unit or Portfolio?

"The SEM Committee's proposed decision is that unit based offers should be the default design for I-SEM [….] it will be appropriate to allow portfolio biding in certain circumstances. Portfolio bidding for demand will necessarily be allowed [….] In addition the SEM Committee sees merit in allowing the continuation of portfolio bidding for aggregated generator units and for demand side units [….] The SEM Committee also considers it beneficial to allow portfolio bidding for variable generation.

SSE agrees with the proposed decisions on bidding and offers. Portfolio bidding effectively allows market participants to separate the physical characteristics of electricity from its commercial characteristics. **While this might be attractive for the management of a large number of small wind generation units, it isn't necessarily useful for the optimisation of the small number of conventional units on the system.**

As stated in our original response, there are two reasons that it is difficult and unattractive to separate out the physical and technical characteristics of electricity generated by conventional stations from commercial characteristics:

- There are many non-energy related issues that are important in the management of a small synchronous island system with high variable renewable penetration. **Physical and locational characteristics should be provided to the TSO soon after the DA schedule so they can effectively manage these issues.**

- Most utilities will be participating in the market with a single power plant, non-dispatchable generation and interconnection capacity (if available) or a concentrated generation market to cover gaps through planned or forced outages at that plant. This does not constitute an effective portfolio. **All of the benefits of portfolio bidding (whether net or gross) would accrue to one participant.**

SSE therefore believes that the retention of unit bidding for conventional units would provide value to the TSOs, most participants, RAs and ultimately consumers.

Allowing wind generation to participate on a portfolio basis would minimise complexity for market participants, TSOs and RAs and lower transaction costs and entry barriers for small wind participation. Wind portfolio participation also preserves the current aggregation arrangements which have facilitated wind entry.

SSE would also highlight an additional consideration with regard to the transitional mechanism proposed. Without portfolio bidding for wind, an aggregator of last resort would effectively remove any incentives for market participants to manage their wind assets in the market. **SSE agrees that demand, AGU, DSU and variable generation should all be allowed to participate on a portfolio basis.**

Intraday and Balancing

Intraday

Participation

"Intraday trading will be exclusively through the European market coupling arrangements and will be on a continuous basis, although periodic auctions might be accommodated. Market participants can start trading in the IDM once DA schedules and INCs/DECs are in place."

The proposed structure and timing of the intraday market is clear. Given that the DA auction will provide a commercial starting point for all units, the ID market will act as a central optimisation window for the Irish market. Incentives to participate in the ID market will flow through from the design of the balancing market arrangements and imbalance pricing. SSE therefore believes that ID is closely linked to balancing, given the potential for arbitrage between the two.

Applying the concept of exclusivity should ensure some level of liquidity regardless of the strength of incentives to balance. SSE does not believe that there is any market benefit to the TSO or market participants in allowing intraday adjustments within portfolios. How liquid the ID market will be is unclear due to delays in the delivery of the European Intraday Platform[31].

The European Intraday solution is fundamental to Irish balancing

Delays in building the European Intraday platform and lack of clarity around the timelines for the delivery of XBID are a major concern for I-SEM. The intraday platform has been held up for a number of reasons:

- Remuneration of transmission capacity
- Pan European Settlement
- Treatment of Losses

These are not simple issues to resolve. The continuous trading model is complex but necessary; participants cannot wait for an auction to buy or sell the power they need to resolve an imbalance position that has been revealed in real-time. **Given the importance of intraday to I-SEM, SSE believes that Irish balancing arrangements are likely to need a transitional period.** Market participants' exposure to the volatile marginal pricing in balancing and imbalance, chosen in the proposed decision paper, will be unnecessarily high without a fully functioning European intraday solution.

[31] We understand that power exchanges have selected an IT service provider, and have been working in parallel but there have been no clear deadlines for delivery available yet.

Balancing

Sources of uncertainty

Certain design features of a balancing market could make trading, scheduling and risk management particularly difficult for renewable generators. In a traditional power system, there are three main sources of uncertainty:

- **Demand uncertainty** (varying with load volatility and creating either a supply deficit or excess supply)
- **Power Plant Failure** (forced outages on the day that would cause a supply deficit)
- **Variable uncertainty** (imperfect meteorological information at the forecasting stage translating into supply deficit or excess supply)

Of these, **variable uncertainty** will be the largest source of forecasting error at the DA market stage in Ireland. Forecasting will improve the closer to real-time that trading can take place. Therefore variable generators will tend to be major 'customers' in the intraday and (indirectly) through the balancing market.

Balancing and wind generation

Given that variable generators are taking on a substantial commercial risk in I-SEM, we are assuming that they will have a firm physical/commercial position, and will not be considered a 'price taker' in the balancing arrangements. **Variable generators will therefore be able to bid in INC or DEC bids that reflect the true value of changes to that physical position[32].** By managing these commercial risks, the incentives to deliver an energy dispatch and ultimately system that provides adequate physical access[33] will shift to the TSO.

Point of intervention?

"The balancing market will open after the DAM results have been published and the TSOs have initial physical nominations following EUPHEMIA. The balancing market will remain open until at least one hour before real-time with detailed market timings to be established as part of the detailed market design."

Considering the size of the Irish market, likely participation if the market is voluntary up to the gate closure of the ID market, and the major impact of imbalances on frequency[34], SSE believes that the TSO should have a reasonable number of regulating bids and offers[35] available from the market. **Requiring bids and offers from the DA stage onwards avoids the volatility and risk implicit in a thinly traded voluntary market.**

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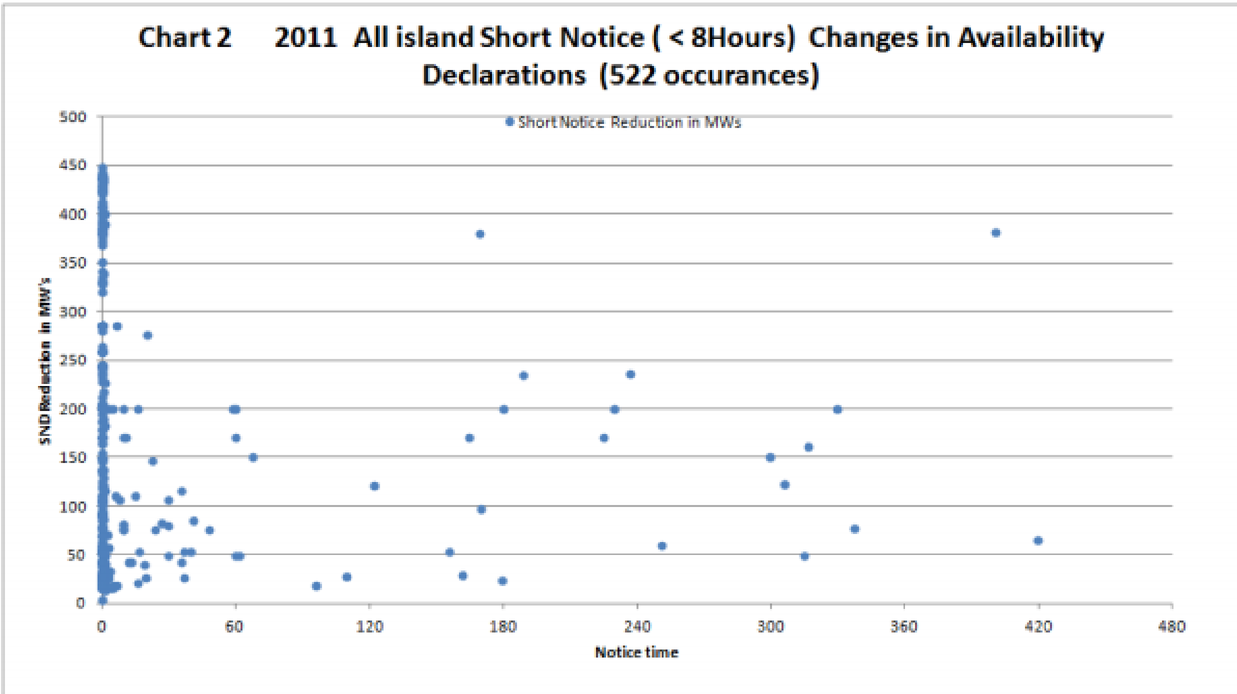
[32] This will include the value of support mechanisms that pay out on metered output, i.e. Renewable Obligation Certificates, REFIT Floor Price and CfD FiTs.
[33] This should cover both curtailment and constraint.
[34] Short notice changes in availability declarations under the current SEM are shown in the chart below.
[35] Regulating offers are prices to increase or decrease production and consumption in real time.



However, EUPHEMIA will be producing a commercial rather than a dispatch schedule. Given the single pricing regime chosen and the penalties associated with imbalance, market participants must be given a chance to resolve their imbalances and optimise their operating pattern without TSO intervention. **The rules for classification of energy and non-energy actions are a detailed design issue, but we would expect that in practice, there will be very few instances where energy balancing actions should be taken prior to gate closure.**

Quantum of benefit?

"The SEM Committee proposed decision is that the balancing market will employ a marginal pricing mechanism. This means that the last unit used to provide balancing energy will set the price for all activated balancing energy [....] actions taken by the TSO for non-energy reasons will be subject to a pay as bid pricing regime."

The marginal pricing mechanism proposed will create very strong incentives for participation in the Balancing Market. It will also ensure that prices are cost reflective i.e. that they properly reveal the actual value of 'flexibility' of energy on the system in real-time. However, this will be a one-dimensional value for flexibility – flexible plant will also need the revenue streams provided through DS3 System Services.

The IPA Energy and Water Economics paper[36] reveals market concentration in the ancillary services market. Similar market concentration exists for flexible plant, particularly with regard to storage and hydro. The proposed decision paper outlines **proxies for structural reform** including a Virtual Power Plant (VPP) auction. **Given market concentration, SSE suggests that a VPP or Directed Contract auction would have best effect in this market segment:**

[36] IPA Energy and Water Economics (2014), Economic Appraisal of DS3 System Services for the Commission for Energy Regulation and the Utility Regulator

- It would reduce financial incentives on dominant participants to exercise market power.
- It would allow smaller suppliers and generators to mitigate the volatility, complexity and risk of the imbalance pricing regime (as eventually defined).

Imbalance Settlement

Single Pricing Regime?

"The SEM Committee's proposed decision is that there will be a single imbalance pricing regime. This will mean that Balance Responsible Parties (BRPs) with a long position in imbalance settlement (contracted position > allocation) will pay the same imbalance price as BRPs with a short position (contracted position < allocation) in the same imbalance period."

SSE agrees with the choice of a single imbalance pricing regime, although we would question why, what is effectively a detailed design decision, has been taken with very limited exploration of the two different approaches in the Irish context. In very simple terms, we would characterise the differences between single and dual imbalance pricing as:

- **Dual pricing:** incentivises participants to act to remain 'internally' balanced
- **Single pricing:** incentivises participants to act to balance the system as a whole

The paper states that this decision has been taken because single pricing:

- Reflects the costs of actions taken by the TSOs
- Signals an incentive to balance rather than a penalty for imbalance
- Promotes the interests of consumers rather than traders
- Does not favour larger market participants

We would appreciate further detail on the economic rationale for a single pricing regime in the final decision paper. In particular, we think it would be worthwhile looking at behaviour in markets which have comparably strong incentives for participants to act to balance the system as a whole. That said, given the high level of variable generation in Ireland, it would be unrealistic for many participants to reach a perfectly balanced 'internal' position.

We are assuming that, conventional units would be providing offers on a unit basis, and variable units would be participating on a portfolio basis. Therefore, imbalances for variable generation would be settled on a portfolio basis and imbalances for conventional generators would be settled on a unit level. To settle wind imbalance on a unit basis would unnecessarily penalise smaller wind generators: they would receive much higher balancing discounts on Power Purchase Agreements (PPAs) to account for the larger forecast error at a unit level.

Quantum of benefit?

"All market participants will be balance responsible (although some market participants may discharge the accounting for imbalances through aggregation agents). This means that all physical volumes not settled through the DAM and IDM are settled at the single marginal ex post price for each settlement period reflecting the marginal costs of energy balancing actions taken by the TSO."

Similar to the pricing mechanism proposed for balancing, the pricing mechanism in imbalance settlement will create very strong incentivises for participants to 'guess' the length of the system and act accordingly. Being on the right side of an imbalance might be very lucrative in certain settlement periods.

However, given that the overall balancing error in Ireland will be greater than GB due to system characteristics rather than participant behaviour, it does not seem ideal to enforce a volatile and penal imbalance calculation formula, particularly when the generation market remains heavily concentrated and vulnerable to the exercise of market power.

Even in the existing SEM which 'dampens' price volatility, there can be substantial differences between ex-ante and ex-post SMP as a result of balancing energy actions[37] as shown below:

Recent Months	SMP		Difference
	Ex Ante	Ex Post	
Jan	£56.19	£58.53	-£2.34
Feb	£49.43	£49.34	£0.08
March	£48.91	£54.01	-£5.10

Selected Days	SMP		Difference
	Ex Ante	Ex Post	
21/01/2014	£78.41	£53.94	£24.48
02/02/2014	£57.22	£50.03	£7.20
10/03/2014	£47.50	£78.35	-£30.85
11/03/2014	£44.65	£80.36	-£35.71

Given market power concerns and the likely quantum of overall system balancing error, SSE believes that the RAs should explore a Price Average Reference[38] (PAR) higher than 1MWh for calculation of imbalance prices. Marginal pricing in the balancing market could be retained through a fund that collects the residual requirement across all demand, blunting exposure and limiting incentives to exercise market power.

[37] Among other factors.

[38] The calculation of the imbalance price would be based on an average of the most expensive offers accepted in the imbalance mechanism, rather than the most expensive offer.

Imbalance pricing as defined could be vulnerable to the exercise of market power[39], and will increase volatility, complexity and risk for participants. This may make participation in I-SEM more difficult for smaller generators and suppliers.

If imbalance pricing is to be truly marginal, SSE believes that a proxy for structural reform will be required i.e. that dominant participants are forced into a VPP for flexible plant. This would limit incentives for the exercise of market power in the balancing and imbalance period.

Capacity Remuneration Mechanism

"[T]he SEM Committee remains of the view that an energy only market will not in practice deliver long term generation adequacy on the island of Ireland. The SEM Committee's proposed decision is therefore that there should be some form of explicit capacity remuneration mechanism (CRM) in the I-SEM and that this can be implemented insuch a way as to avoid distorting cross border trade."

As most participants stated in their responses, an explicit CRM will be required under the HLD. Ireland faces **indivisibility, price indifference** and **market power** issues. These cannot be effectively (or attractively) mitigated in an energy only market. This was revealed in the TSOs Assessment of Generation Adequacy in an energy-only market - a significant proportion of capacity is removed from the market from 2017:

	Removed (O&M costs only)			Removed (Capital + O&M Costs)		
Gen Type	2017	2020	2023	2017	2020	2023
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	N	Y	N	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	Y	Y	Y	Y	Y
Gas OCGT	Y	N/A	N/A	Y	N/A	N/A
Gas OCGT	Y	N/A	N/A	Y	N/A	N/A
CCGT	Y	Y	N	Y	Y	Y
Heavy Fuel Oil	Y	Y	N/A	Y	Y	N/A
Heavy Fuel Oil	Y	Y	N/A	Y	Y	N/A
Heavy Fuel Oil	Y	Y	N/A	Y	Y	N/A
Heavy Fuel Oil	Y	Y	N/A	Y	Y	N/A
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Distillate OCGT	Y	Y	Y	Y	Y	Y
Total Capacity Removed (MW)	2062	1960	815	2152	1960	1368

[39] Participants with the ability to substantially alter system position who also own flexible units could push the system into a position desirable for their portfolio, or undesirable for other participants.

An energy-only market with a PCAP of €3000/MWh delivers a very slim capacity margin in a Median Demand scenario with a relatively high IC reliance and a LOLE of 8 hours per year. **This would not be a desirable outcome. SSE agrees with the proposed decision.**

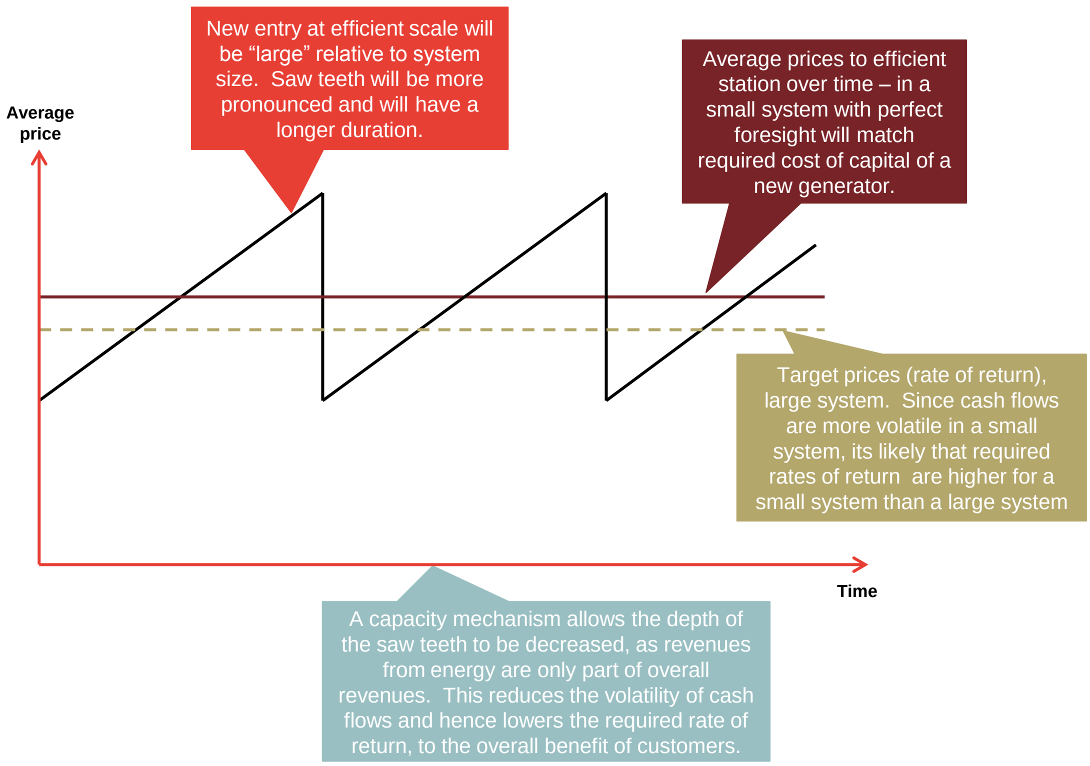
Quantity vs. Price

"Having considered the various design options for CRMs further, having taken on board the views set out in the consultation responses and having considered international best practice and academic research in this area, the SEM Committee's proposed decision is that a quantity based scheme is in the best interests of all-island consumers."

The reasons for this decision are stated as:

I. **Quantity based CRMs will provide a more competitive market based solution for the valuation of capacity than a price based scheme.**

   This is taken directly from the EU State Aid Guidelines on Energy and Environment. Markets may be better at discovering a value for capacity rather than a quantity of capacity. However, given that a CRM is attempting to provide a stable, accurate signal to build, maintain or close capacity, a very responsive capacity price on an annual basis would be counterproductive. It would simply replicate the issues in an energy only market, illustrated in the figure below. Competitive markets provide responsive prices.



A quantity based CRM does not substantially dampen the saw teeth – an annual auction will clear at a level which reflects the value of the derivative.

The derivative for existing plant will be an annual product and the value of the derivative will reflect its contractual cash flows in possible future states of the world. The probabilities of various possible future states of the world will always be limited if you are auctioning an annual product, therefore the value released at each auction will be volatile as the system moves between surplus and deficit. **While competitive price discovery is beneficial for customers – any CRM is likely to require regulatory intervention to 'bound' price responsiveness.**

II. Quantity based CRMs should provide a more proportionate response than a price based scheme.

Quantity based CRMs are simpler than price based CRMs. Auctions, rather than regulators assess and account for interactions between the capacity, energy and system services revenue streams lie. The SEM Committee's paper on DS3 makes the following assessment:

Table 13 Potential Interactions with the Capacity Remuneration Mechanism (CRM)				
Service	Regulated Tariff		Multiple Bid Auctions	
SIR	Capability	Greater interaction	Availability	Interaction
FFR	Availability	Interaction	Availability	Interaction
FPFAPR	Capability	Greater interaction	Availability	Interaction
SRP	Capability	Greater interaction	Availability	Interaction
DRR	Capability	Greater interaction	Availability	Interaction
Op Reserve	Dispatch	Less interaction	Dispatch	Less interaction
RRS/RRD	Dispatch	Less interaction	Dispatch	Less interaction
Ramping	Dispatch	Less interaction	Dispatch	Less interaction

In a price based mechanism, the extent to which the clearing prices or regulated tariffs should be reflected in the capacity price must be assumed by the RAs for each of these products. This will be less efficient than a quantity based mechanism.

III. Quantity based CRMs can be designed more appropriately than price based schemes to mitigate against undue cross border trade distortions

Quantity based CRMs feed into near term energy prices less directly than price based mechanisms, which should mean that interconnector flows reflect fundamentals rather than arbitrage between capacity mechanisms. However, cross border access is more difficult to address under a quantity based scheme. In the long run, this may distort investment decisions in the respective markets.

IV. Quantity based CRMs can be tailored to address issues such as flexibility more easily than price based schemes.

Flexibility is a very different service to capacity. It is not clear why a capacity mechanism should be designed to reward flexibility, given the nature of the service provided. If we contrast two situations in which price signals incentivise behaviour:

- **Wind generation sharply drops from 1000MW to 600MW over the course of 15 minutes:** Additional capacity is required, but a limited number of units can provide it in the time period required, because the requirement is unpredictable. There is no overall scarcity on the system but there is segmental scarcity; a limited number of generation and DS units are able to technically respond in the time period required.

- **System demand rises to an annual peak:** Additional capacity is required, but any generating or DS unit on the system can provide it, because the requirement is predictable. There is overall scarcity on the system: most generation and DS units will be required to respond in order to maintain system security.

The first scenario requires a short-term price signal because the requirement is unpredictable and requires response close to real-time. **The units dispatched are rewarded through energy balancing arrangements, with the units that caused the system scarcity subject to imbalance settlement.**

The second scenario requires a long-term price signal because the requirement is predictable and requires a long-term response (i.e. an investment decision to build, maintain or close). **The units dispatched are rewarded through a capacity remuneration mechanism with limited year to year price volatility.**

Confusing the two revenue streams would mean that you place a constraint on the units that can remain on the system to resolve the second scenario and oversupply the units required to resolve the first scenario. You would build expensive new capacity on the basis that they could provide capacity in the first scenario rather than maintaining cheaper depreciated old capacity. This would unnecessarily increase costs for end consumers.

V. Schemes under consideration in other NWE markets are quantity based.

There are a number of different NWE CRMs under consideration. The UK has opted for a central buyer, France has opted for decentralised buyers and Germany is currently undecided as to which CRM would be most effective. **This reflects the EU State Aid Guidelines on Energy and Environment.**

Taking these points into consideration, SSE would agree with the choice of a quantity based mechanism, with the following caveats:

- Too much price responsiveness is not a desirable characteristic, given the objectives of a capacity mechanism[40]. Market based mechanisms deliver a great deal of price responsiveness, alongside other things.
- Quantity based mechanisms run less risk of near term scheduling distortions, but more risk of long term investment distortion, if cross border participation is not designed correctly.
- Flexibility is a different product to capacity. If investors in new plant cannot compete with existing plant in providing low cost capacity[41] then they are not required on the system. Setting constraints on capacity type merely increases costs for end consumers.

Centralised Reliability Options?

"Having considered the reasons for needing a CRM in the I-SEM and having taken into account the responses received, researched international experience and relevant peer reviewed academic literature in the area, the SEM Committee's proposed decision is that the form of CRM should be Centralised Reliability Options (ROs) issued by a central party."

There are two parts to any capacity mechanism:

- **Existence:** Ensure that there is sufficient capacity built to meet demand.
- **Availability:** Ensure that sufficient capacity is available when required.

So, any design should achieve a minimum desired supply security level by encouraging new capacity to be built and existing capacity to remain on the system[42]. It should provide that capacity price signals to be available at times when the total system margin is low.

Do Centralised Reliability Options incentivise plant to be available?

This can very simply be illustrated through a calculation of the potential penalty a generator could face if they were unavailable during a period in which the reference price for a Reliability Option exceeds the strike price for a 400MW generator.

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[40] A CRM should deliver a stable long run price for physical capacity.
[41] Their cost of delivery is offset by the revenues they receive for flexibility in energy and system services markets
[42] Getting the balance right between new and existing capacity should generally be resolved by the energy arrangements, rather than the capacity arrangements

	Generator A (running)	Generator B (not running)
Periods	6	6
Strike Price	€1000/MWh x 400 x 6	€1000/MWh x 400 x 6
Achieved Price	€3000/MWh x 400 x 6	€0 x 0 x 0
Repayment	€2000 x 400 x 6	€2000 x 400 x 6
Liability	€0	**€5,760,000**

In this example, **generator B has incurred a liability of almost €6 million over the course of 6 trading periods. This does not include the market opportunity cost of almost €2 million that the generator would have normally incurred for being unavailable during these 6 trading periods.** Liabilities of this severity will certainly incentivise a plant to be available.

However, the severity of the penalty arrangements creates other issues:

- **Substantial collateral requirements**
  Without any form of capped liability, providers of reliability options may be forced to post substantial amounts of collateral. The paper simply states:

  "The collateral arrangements associated with Reliability Options will be an important feature of the mechanism, which will impact on both provider and buyer. Providers may need to provide collateral arrangements to cover events where the reference price is higher than the strike price."

  One of the design features of the Reliability Option is the pure/uncapped nature of the liability. Collateral requirements could potentially be larger than the option fees received. This would limit participation to those generators willing or able to meet them, forcing the clearing price above the actual price of capacity. It would also add costs for customers, because generators would need to recover the cost of borrowing.

- **Incentives in reference market**
  Participants with sufficient portfolio scale will have incentives to game the interactions Reliability Options have with their reference market. If we take an example of a portfolio generator that has entered a de-rated[43] quantity of capacity into the central auction - the quantity of capacity that clears in the reference auction will be potentially less than their technically available capacity.

  Capacity that is not covered by a Reliability Option will not be capped in the reference market. **The portfolio generator with market power will be incentivised**

[43] De-rating is a detailed design question, but would mean that a unit's capacity is adjusted (centrally/generically) to take account of its likely technical availability at peak demand, specific to each type of generation technology.

to push the price above the strike price for the Reliability Option to outperform its fixed costs during periods of system scarcity and trigger liabilities for competitors who have also sold Reliability Options. This incentive to trigger excessive system price events is a substantial risk in concentrated wholesale markets and unique to Reliability Options.

Do Pure Reliability Options incentivise existence of plant?

Existence is primarily about getting to a stable resolution of the 'missing money' problem identified in the consultation paper. The paper appears to be agnostic on whether physical or financial Reliability Options would best deliver physical capacity.

"Pure reliability options do not have additional penalty mechanisms for non-delivery other than the amounts paid back when the RO is called. However, other markets have considered combining reliability options with penalties for physical non delivery. The requirement for these in the I-SEM context is not clear at this stage and this will be an issue to be considered in the detailed design of the mechanism."

Pure Reliability Options do not even attempt to solve the missing money problem, because they mean that the auction described is trying to value **expected scarcity** rather than the **physical capacity** required to deliver a desired reliability standard.

In the Irish context, an issuer could participate in an auction on the basis of a **'credible generation project'** i.e. a Gate 3 offer[44]. Instead of calculating the cost required to support their physical position in the market (i.e. annual fixed costs), they would simply calculate the value of the Reliability Option as an American Call Option with a risk premium. The option would become a liability, the option payment would become a revenue line, and the liability could be offset by a corresponding asset[45]. **That corresponding asset wouldn't necessarily need to be anything as illiquid as a power station; it could be a conventional Treasury Gilt.**

Pure reliability options with limited pre-qualification and non penalties for physical non-delivery will not deliver a desired reliability standard. They will simply financially hedge suppliers up to the Day Ahead price cap, and provide a limited revenue stream for participants willing provide the associated insurance product.

Does an intraday or imbalance reference price incentivise the existence of plant?

"Consideration will be given as part of the detailed design on which the best reference price and whether an intraday or balancing price could be used to incentivise greater flexibility from providers."

As stated in the quantity vs. price section, flexibility is a very different service to capacity. Our earlier example of price signals incentivising behaviour is restated below:

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[44] This 'credible generation project' may not even necessarily have planning permission.

[45] This is also true for cross border participation. Cross border generators could participate up to the volume of FTRs offered by the Interconnector owner. In the case of FTR Obligations, this could be higher than the rated capacity of the interconnector. They would be insuring suppliers against price spikes, but they would be making a very limited contribution to the desired reliability standard.

- **Wind generation sharply drops from 1000MW to 600MW over the course of 15 minutes:** Additional capacity is required, but a limited number of units can provide it in the time period required, because the requirement is unpredictable. There is no overall scarcity on the system but there is segmental scarcity; a limited number of generation and DS units are able to technically respond in the time period required.

- **System demand rises to an annual peak:** Additional capacity is required, but any generating or DS unit on the system can provide it, because the requirement is predictable. There is overall scarcity on the system: most generation and DS units will be required to respond in order to maintain system security.

In these scenarios, there is no clear intraday price. Contracts will be settled bilaterally on the XBID platform. **Given that the XBID platform has not been delivered there is no expectation of whether there will be sufficient liquidity or a price reporting service for Ireland**. In the first example prices will reflect imbalance price expectations as participants attempt to cover their imbalance position. **An intraday price is clearly the incorrect reference price for a Reliability Option.**

There will be a clearing price in the balancing market, but that price will reflect the first rather than second scenario. It will be incentivising generation units that can technically respond to a rapid change in system conditions. The balancing market price will also rise in the second scenario, theoretically to VOLL[46]. Both the first and second circumstances will trigger repayments under the Reliability Options. However:

- Some units will have been re-dispatched earlier on a Pay-As-Bid basis to resolve non-energy constraints, despite the fact that they were available to deliver the energy required during the system price event. Generators will have to factor in the risk of constraints into their offer for Reliability Options. The Balancing Market is not like the Day Ahead Market – it is effectively constrained. This risk will be very difficult to value for potential physical providers of capacity, distorting the outcome of the central auction.

- The price events in the Balancing Market (i.e. reference price rising above the strike price) will also be far more frequent than in the Day Ahead Market. Because the Balancing Market will be providing both short-term and long-term price signals, price events will happen all year around. This is not desirable for the issuer of a reliability option, because any planned or forced outages translate into a substantial exposure, unless they can be covered in a secondary market.

Any movement away from a **Day Ahead Reference Price** is effectively confusing multiple products and revenue streams – by using an Intraday or Balancing Market reference price:

- You place additional non-energy risks on physical issuers which will be reflected in the clearing price in the auction.

[46] Balancing Market prices will not be capped, unlike the DA market.

- You place an unnecessary constraint on delivery of the physical capacity required to meet the desired reliability standard.
- You increase price volatility in the annual auction by involving uncertain, subjective costs beyond delivery of physical capacity.

Ultimately, customers will be paying to oversupply flexible capacity, because the balancing market and system services revenue streams are already designed to fully compensate those products. **By oversupplying flexible capacity, you will distort short-term price signals in the Balancing Market and misprice the DS3 system services auctions. This is not a desirable outcome – it is not clear why the RAs want to expand the focus of a Capacity Mechanism beyond resource adequacy.**

Will an annual product and annual auction adequately incentivise the existence of existing plant?

A capacity market needs to provide a sustainable, consistent and predictable market for capacity to provide a long-term investment signal for generators (to open/maintain/close). As stated previously, a central auction for Reliability Options will clear at a level which reflects the value of the derivative.

If the derivative for existing plant is an annual product, the value of the derivative will reflect its contractual cash flows in possible future states of the world. The probabilities of various possible future states of the world will always be limited if you are auctioning an annual product, therefore the value released at each auction will be volatile. **While competitive price discovery is beneficial for customers – any CRM is likely to require regulatory intervention to 'bound' price responsiveness with a cap and floor.**

Without 'limiting' price responsiveness, Centralised Reliability Options cannot provide the stable income stream needed to incentivise existing generation.

Will an annual product and annual auction adequately incentivise new plant?

"The delivery timeframe sets out the time lag between the RO auction and commencement date of the RO contract. In the GB capacity mechanism this time lag is four years. The contract length is another important parameter. In the GB capacity auction, existing players get a one year contract while new entrants and retrofit plants get longer contract durations."

A secondary point is that annual products cannot bring forward new plant. A lead-in-time will be required to bring forward any new investment, but given that there can be no gap in the price signal for capacity, there is insufficient time between now and market-go-live to offer any other than an annual product for market go-live. This needs to be resolved in detailed design.

Concluding Remarks

Energy Trading Arrangements

SSE believes that the Energy Trading Arrangements proposed can deliver for Irish consumers, with some minor additions:

- A Forward Market Making Obligation on vertically integrated participants.
- A Central Forward Trading Platform with an independent clearing house.
- PTRs, with FTRs introduced if PTRs are not delivering.
- A VPP auction for flexible (storage) units.
- More analysis of the appropriate price reference for imbalance pricing.

Capacity Arrangements

SSE is less confident that the proposed Capacity Arrangements can deliver for Irish consumers. If a quantity based mechanism is chosen, we believe the following design elements are necessary:

- Centralised Reliability Options.
- A price stability mechanism in the central auction.
- A Day Ahead Reference price.
- Careful consideration of incentives to exercise market power in the reference market.
- Robust physical backing requirements.
- A strict focus on resource adequacy, excluding flexibility.

Detailed Design

We look forward to working with the RAs Project Office on the detailed design arrangements. The project plan states that this work will take place between September 2014 and February 2015, with delivery of a detailed design in February 2015. Given the range of issues that need to be covered, we think that this is unrealistic. There are elements of design that need to be finalised for implementation and elements of design that can be finalised later.

The RAs should fully utilise the expertise that market participants have in the detailed design phase by setting up technical working groups on individual design elements. For elements that will clearly require further work (i.e. Forward Liquidity) these should be set up in advance of the publication of the Final Decision.

Annex A

Abbreviations

AGU	Aggregated Generation Unit
BM	Balancing Market
BRP	Balance Responsible Party
CACM	Capacity Allocation & Congestion Management
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Difference
CfD FiT	Contract for Difference Feed in Tariff
CRM	Capacity Remuneration Mechanism
DA	Day Ahead
DAM	Day Ahead Market
DCENR	Department of Communication, Energy and Natural Resources
DEC	Decremental
DETI	Department of Enterprise, Trade and Investment
DS3	Delivering a Secure Sustainable System

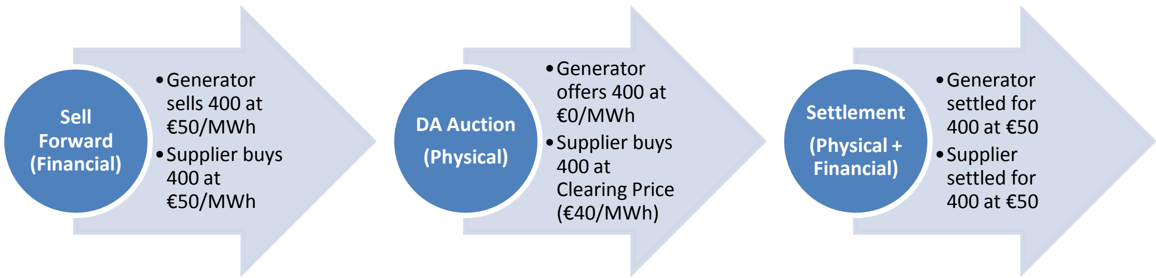
DSU	**Demand Side Unit**
EC	**European Commission**
EPM	**Energy Portfolio Management**
ETA	**Energy Trading Arrangements**
EU	**European Union**
FTR	**Financial Transmission Right**
HLD	**High Level Design**
IC	**Interconnector**
ID	**Intraday**
IDM	**Intraday Market**
INC	**Incremental**
I-SEM	**Integrated SEM**
MSQ	**Market Schedule Quantity**
MSP	**Market Scheduling and Pricing**
NWE	**North West Europe**

Ofgem	**Office of Gas and Electricity Markets**
PAR	**Price Average Reference**
PCR	**Price Coupling of Regions**
PPA	**Power Purchase Agreement**
PTR	**Physical Transmission Right**
RA	**Regulatory Authority**
REFIT	**Renewable Electricity Feed in Tariff**
RES	**Renewable Energy Sources**
RO	**Renewable Obligation**
SEM	**Single Electricity Market**
TSO	**Transmission System Operator**
UIOSI	**Use It Or Sell It**
VOLL	**Value of Lost Load**
VPP	**Virtual Power Plant**

Annex B

Converting a Financial Forward into an 'effective' Physical Forward to remove scheduling risk

Despite concerns expressed by a number of participants, there is a very simple solution available to convert a Financial Forward into a Physical Forward, removing scheduling risk:



Without a **Bidding Code of Practice**, participants can effectively self schedule, therefore financial only forwards can be converted into physical positions. **This is why a Centralised Platform for Financial Forwards and Market Maker Obligations are required.** Without these measures, market dominance becomes a very real risk, especially if suppliers can pass on the cost of their financial forwards to regulated retail customers. This would be a particular risk in Northern Ireland.